Proceedings of Seminar

Economics of Industrial Cogeneration of electricity

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THE ECONOMICS OF INDUSTRIAL COGENERATION OF ELECTRICITY

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Introduction

Over the past few years conservation of energy within the industrial sector has been taking on an increasingly important role in the form of cost reduction programs. Cogeneration, which can be defined as simultaneous production of process steam and electricity at the industrial site, can become one of the components in these programs. Many plants in Ontario with process steam requirements have undertaken feasibility studies to determine the economics of generating their own electricity. In order to do these studies a great deal of information is required such as:

(1) government policies regarding possible incentives and the write-off for tax purposes,
(2) Ontario Hydro's pricing structure for the plants' surplus power,
(3) equipment costs,
(4) fuel costs and availability in the next 20 years, and
(5) the possible envrionmental impact of cogeneration development.

Many of the industrial operators have turned to Ontario Hydro and the Ontario government for this information. As the number of these enquiries have increased, it was decided to bring together all of the interested parties on this subject and to give them the opportunity to discuss their concerns and exchange information.

This was the reason behind the seminar on the "Economics of Industrial Cogeneration", held on December 13 and 14, 1978, in Toronto. It was attended by 200 people, comprised of senior technical and operating management from industry, consultants, suppliers and representatives of Ontario Hydro and the Ontario government. The seminar was structured in such a way as to permit questions and discussion following each paper, which also appear in this book following the papers.

The seminar was officially opened by James A. C. Auld, Minister of Energy. He stated that the Ontario Government's energy policy is to provide a climate encouraging the maintenance of a balanced supply of energy, with due regard to its impact on the environment, and with a full recognition of Canada's limited resources of fossil fuels. He also stressed the importance of cogeneration development in the pulp and paper industry, since "it both solves a wood-paste problem and makes effective use of a fuel indigenous to the province." Later in his presentation he outlined certain obstacles and objections to cogeneration which he hoped the seminar might answer. They are:

(1) Ontario Hydro has a large reserve margin at the moment;
(2) energy conservation programs have already reduced electrical demand in many plants,
(3) natural gas may not be the best source of fuel for cogeneration, since two years ago the government forbade the use of it for this purpose;
(4) cogeneration in European countries is decreasing,
(5) Ontario Hydro's pricing policy takes account of the most efficient use of its own generating capacity, and therefore the purchasing of power from industry might be limited.

However, at the end of his paper he stated that he is committed "to the effective use of energy in all forms", and that he is "prepared to consider reasonable suggestions requiring legislative or fiscal action" in the development of cogeneration.

Dr. Ian Rowe followed the Minister in his overview of the "Future Fuel Availability for Industrial Cogeneration", Dr. Rowe pointed out that all fuels should continue to be available in Ontario for at least the next ten years, all things being equal, but beyond that the availability of crude oil and natural gas will depend on exploration. Coal is expected to become an important future fuel source, as well as forest, agriculture, municipal and industrial wastes. Forest residue alone has "a potential to produce 13 million tons per year of renewable fuel stock."

One of the more important papers delivered at this seminar was by D. D. Dick, summarizing the "Survey of Costs Associated with Industrial Cogeneration In Ontario". In September, 1978, Dick Consulting Services Ltd. carried out a survey of costs associated with cogeneration in 15 industrial establishments. From the study Mr. Dick concluded that the companies which are "equipped with modern facilities integrated with the combustion of salvage fuels enjoy a reasonably high return on their investment in cogeneration." Two paper companies are given as excellent examples of well designed plants for the profitable use of cogeneration. Most others (11 establishments) do not receive an adequate return on the invested capital, because of high fuel costs, uneconomic operation and maintenance, or because the cogeneration facilities were "originally installed for reasons which are now less valid." Mr. Dick concluded that each cogeneration facility is largely unique and specific, and that in most cases the existing cogeneration facilities are not operated efficiently, mostly because the cogeneration units are improperly designed and sized.

In the development of cogeneration Mr. Dick's paper becomes an important reference source since this is the first Canadian cost data published on the subject. Up to now any discussion or studies (such as Leighton and Kidd Study) relied on costs compiled either in Europe or in the U.S. In this report the composite mill rate (mills/kWh) was itemized into fuel costs, operating costs, and capital costs, and the range was calculated for similar units obtained from various plant locations. For example the capital costs vary between about $270/kW for 85 MW unit and $860/kW for 3 MW.

The discussion which followed this paper centered around what discount rate was used in the DCF calculations.

Following Mr. Dick, a paper was presented on the "Cogeneration Potential in Ontario and the Joint Ven-

ture Approach" by A. Juchymenko, who told the audience that a recent study of the industrial market in Ontario conducted by Ontario Hydro estimates the potential for industrial cogeneration in Ontario to be about 720 MW in about 43 plants. The extent to which this potential will be realized depends on how the economic constraints and obstacles can be overcome by industry. The above concerns are universal. In the U.S., for example, the common vehicle for cogeneration development is joint venture between the utility and industrial customers. Mr. Juchymenko went on to suggest an approach that would overcome the major investment operating obstacles referred to by Mr. Dick in his paper, and perceived by industry. A private company could be established to promote cogeneration in the industrial field. Preliminary studies show that the company could be economically feasible without Ontario Hydro's financial support. This company could undertake the design, maintenance and operation of cogeneration facilities, and sell steam and electricity to industry. The on-site facility could be jointly owned by individual industries and this proposed company. An extensive discussion followed.

The last paper of the morning, "Relationship of Industrial Generation and Ontario Hydro's Expansion Program" was presented by Dr. D. A. Drinkwalter. In order to show the alternatives open to industry in the supply of electricity, Dr. Drinkwalter compared the costs of Ontario Hydro's expansion program and the alternative route via industrial cogeneration. The cogeneration costs came from U.S. studies - the only available source at the time of the study. The findings of the study concluded that . . . "cogeneration can be an economically viable alternative to purchasing power from Hydro. For such plants operational in 1985, all but the smallest have returns exceeding 15 per cent". He also concluded "that the potential impact of reduced reliability of power supply from Ontario Hydro would be relatively small."

The luncheon speaker on the first day of the seminar was W. O. Twaits talking about "Industry's stake in Energy Planning". Mr. Twaits pointed out three trends which will effect the development of cogeneration:

(1) cost of energy will continue to increase,

(2) stringent environmental standards for air and water will require more energy; and

(3) the technical complexity of producing goods and services will increase.

He stated that Ontario is an energy-deficient province; it is a "net buyer" and the only controllable energy it has is electricity, since electricity produced by uranium has the smallest future increase in cost production, its basic element being equipment and not fuel. However, the lead times involved in nuclear stations is upwards of ten years from conception to operation, which means that "no political opportunism or vacillation should be allowed". Time also increases costs. Concluding his remarks he said that we cannot fine-tune planning to long-term forecasts of demand which cannot be accurately predicted, therefore:

(1) we must emphasize the adequacy or margin of safety of supply.

(2) we must encourage supplemental sources such as cogeneration,

(3) we must get around the lengthy regulatory approval procedures, and

(4) legislators should keep in mind lead times, and not "tinker" with inter-fuel competition.

The first paper of the afternoon was entitled "New Additions to Ontario's Generating Capacity - Which Alternative is the Most Advantageous for the Industry?" by Sven Erlandsson. This paper compared the cost of electricity to industry for new power generating capacity, regardless of "who is to build it". Mr. Erlandsson showed that the power from a new nuclear station would be more costly than the power from the industrial back-pressure plant, and therefore he concluded that, "it is obvious that new power stations added to the utility network will increase the cost of purchased power." In order to make the above statement Mr. Erlandsson worked through some examples to support his conclusions and suggested how this could be implemented by Ontario Hydro. He also showed what other developments are possible in the cogeneration field such as the pressurized fluidized bed combusion of coal.

The second paper in the afternoon was given by Mr. Gusen on the "Electrical Requirements for Parallel Operation of Cogeneration and Hydro System". Early in his presentation, Mr. Gusen spelled out some of the advantages and disadvantages of the parallel operation both to the customer and to Ontario Hydro. As to the economics Mr. Gusen stated that costs vary from zero, where a small generator is added in a modern plant, to tens or hundreds of thousands where several large generators are being added, or where the plant distribution system is inadequate to withstand and interrupt short-circuit current levels. In these cases additional equipment would be required with higher interrupting capacity. Mr. Gusen also stated that it is not possible to place a general dollar value on these remedial measures but he worked out an example to indicate what factors must be considered before the customer decides to parallel with Ontario Hydro.

Mr. Gusen was followed by Mr. H. C. Palmer presenting a paper on "Rates and Rate Structure for Industrial cogeneration Installation". In his paper Mr. Palmer enumerated various rates applicable to cogeneration customers and outlined trends for the near future. Mr. Palmer stated that "by reason of possession of his own generation, this customer is likely to be somewhat different from other industrial customers of the same size". Up to now these customers warranted individual attention. Ontario Hydro is prepared to buy occasional surplus power from these customers on the basis of equal sharing of the resultant operating savings to Ontario Hydro. Several cogeneration installations sell this type of power to Hydro on this basis. In the cases where a cogeneration operator

encounters a shortage due to emergency outage of his equipment or due to scheduled maintenance, he may purchase a standby service at about $8 - $10 per year per kW, and when he takes power he would pay the regular rate for consumed power. In the case where the operator chooses not to purchase standby service his minimum billing provision of 75% of the highest peak in the previous 11 months is raised to 90%. At this time no cogeneration operator has offered to sell power to Ontario Hydro on a regular and reliable basis (firm capacity), however Hydro would be willing to discuss this type of arrangement. Mr. Palmer estimates that in 1988 Ontario Hydro would pay about $70/kW per year for firm power. He also stressed the point that the determination of capacity payments for cogeneration will be complex since it will deal with reliability, schedules, and lead times.

Dr. Ian Efford, representing the federal government, outlined next the "Policy Aspects of the National Perspective". With the thought of "Energy saved is energy produced" in mind, Dr. Efford summarized various projects undertaken by the Energy, Mines and Resources Department, which he hoped would remove some technical problems regarding cogeneration. Most of these projects are designed to prove the feasibility of burning forest waste, garbage, peat, farm waste etc. Through federal-provincial agreements, more than $114 million has been provided for the above projects. Dr. Efford also outlined the financial incentives available from the government. In summary it was reiterated that cogeneration, using waste products, would increase industrial efficiency, cut costs, making us more competitive, and cut the cost to the nation of producing new energy.

The last item on the program of "day one" was a panel discussion on the "Cost of Production of Electricity with Wood By-Products" - ("Hearst Study".) The three panelists were R. L. Gudgeon, R. M. R. Higgin, and A. W. Rogers. This project falls into the category of schemes encouraged by the government as mentioned in the previous paper by Dr. Efford.

While day one dealt with conceptual considerations of cogeneration, day two concerned itself with the technological developments and costs associated with the production of steam and electricity.

The morning sessions dealt with the costs of producing steam utilizing various fuels, while the afternoon speakers covered the costs of turbines and the generation of electricity from a given set of steam conditions.

The first speaker of the morning, Professor McGeachy, expertly but simply took the audience through various theoretical vapour power cycles showing their application in the industrial turbine design and operations. Because of the time constraint, Professor McGeachy spent most of his presentation time on the steam turbine. However, his paper, contained herein, also discusses other prime movers such as gas turbines and diesel engines. The last section in his paper deals with methods of upgrading thermal energy by means of heat pumps. Since this technique involves the use of power rather than its generation, in very rough terms it is an inverse process to cogeneration. The thermodynamic principles in this application are very instructive and well worth examining for industrial processes.

The next three speakers in this session talked about costs of producing steam from various fuels, describing steam characteristics at various temperatures and pressures and their application in the generation of electricity.

Mr. Newby in this paper, entitled, "Capital Costs Associated with Industrial On-Site Generation of Electricity in the Pulp and Paper Industry" described two retrofitted steam generators to produce electricity. He showed the difference in cost for two similar installations in the paper plants. In one case the boiler was designed for high pressures, but in fact was operating at low pressures to supply process heat. The other case was a high pressure boiler which was operating at high pressures but did not drive a turbine. The costs per installed kilowatt in the two examples considered were $226 and $217 and "these are reasonably typical for the time they were applicable".

A return to coal fired boilers is generally predicted in North America and Mr. Rivers presented a paper on the "Design and Economic Differences between Coal and Oil Fired Boilers" to highlight some of the major design parameters for these boilers. Since fuel determines the design and capacity of boilers, the design consideration differences "amplify the reason for the difference in size, difference in space and difference in price". In the example given by Mr. Rivers, the coal fired boilers are three times as large as boilers using oil. Consequently the coal fired boilers for 100,000 and 200,000 lbs/hr capacity is three times the price of oil fired boilers. For larger boilers (400,000 lbs/hr) the coal fired are 1-½ to 2 times the cost of oil. In total Mr. Rivers developed 32 approximate selling prices for a specific list of normal steam generating equipment. This table is a ready and excellent reference source for a feasibility study.

Mr. Winship, in his paper the "Use of By-product Fuels for Use in Industrial On-Site Cogeneration", also concentrated on showing relative costs of steam generation for different fuel types and sizes. Early in his presentation Mr. Winship stated that, "steam generators utilizing by-product fuels or gases have long been used by Canadian industry and hence the equipment utilizing these fuels may be considered a mature technology". He then proceeded to show the economics of by-product fuels, pointing out that there are "no technical constraints preventing by-product fuel fired boilers for cogeneration projects operating at high temperature and pressure". Especially when recent studies have shown that . . . "power generation tends to favour the highest steam pressure and temperature . . . (15000 psig 950°F)."

The luncheon speaker on "day two" was T. E. Gieruszczak who sketched out "A Utility's View on Cogeneration". After briefly reviewing the energy scene touching on the current surplus of natural gas in Canada, our imports of oil, and other energy develop-

ments, he stated that, "it would appear that under today's energy scenario, there is a great potential in Ontario for Cogeneration". Then he went on to describe his company's interest in cogeneration and concluded that industry, government and the electric and gas utilities should use their imagination and work closely together to develop a program to facilitate accelerated development on industrial by-product power.

In the afternoon session four papers were presented all dealing with the cost of turbines and their efficient operations. Mr. Neary described the operation of the gas turbine, its characteristics and its economics, using actual installations to show its application. He pointed out that the return on investment in a cogeneration system can be determined by considering six variables. The variables are:

(1) Utility Electrical Rate ($/kWh);
(2) Annual Utilization (%);
(3) Fuel Cost ($/million BTU);
(4) Installed Cost of Co-generation system ($/kW);
(5) Net Fuel Rate (type of heat recovery);
(6) Maintenance Cost.

To summarize the finding for his examples, Mr. Neary prepared a cost flow table for a quick calculation of annual cash flow for fifteen years. He then applied these calculated figures in a specific example to show a rate of return to vary between 18% and 24% depending on the installed costs and other assumptions.

Following Mr. Neary, a paper on "Steam Turbines, their Cost and Application" was present by Mr. J. B. McCullum. The paper reviewed the theory of power cycles, applying it to industrial cogeneration. Then Mr. McCullum developed several charts to bring all the costs associated with steam turbine specifications onto one sheet for estimating purposes and ready references. He showed that installed costs for turbine only varies between $100/kW and $150kW. Later on in his paper he prepared other charts to assist engineers in the calculation of annual return on incremental investment and multipliers for their back pressure steam turbines. This paper contains a great deal of information on cost of steam turbines, and as other papers presented at this seminar, it will be an excellent reference source for estimating purposes and preliminary analysis of cogeneration feasibility studies.

The third paper in the afternoon was entitled "Importance of Steam Balance for the Economic Operation of Industrial On-site Generation", presented by J. R. Parrott. Mr. Parrott described an actual operating condition which exists at the Great Lakes Paper Company in Thunder Bay. He reviewed energy costs and established the cost of steam, pointing out that more than 50% of their heat value came from waste fuel. In order to operate their cogeneration facilities efficiently, the demand for steam and electricity should be balanced, since "back pressure turbine produces electric power in proportion to the steam flow. This balance is difficult to sustain for long periods of time, and when it is upset, the steam plant may spill steam and hence waste energy." Mr. Parrott estimates that "losses for the whole plant in four years could possibly exceed $1,000,000". This is a significant loss and Mr. Parrott goes on to show how this can be prevented with assistance from Ontario Hydro.

The last paper at the seminar was by Mr. A. Schwarzenbach entitled "A Typical Industrial Cogeneration Project". This paper describes a feasibility study conducted by a consulting firm for chemical plants in Luisianna, U.S.A. Using the existing steam and electricity conditions at these plants and assuming other necessary criteria for the study, the paper points out that the resultant cost of steam for processes to the plants with cogeneration will be lower by 20 percent.

The concluding remarks to the seminar on "The Economics of Industrial Cogeneration" was delivered by Mr. D. J. Gordon, President, Ontario Hydro. He stated that "the primary objective of the seminar was to put cogeneration into focus for all of us; government, the utility, industry, the consultant, and the manufacturer". He then delineated various roles and responsibilities of these groups and their potential contribution to the solution of energy supply and cost problems facing the Ontario industry. In conclusion he outlined a program to be initiated immediately as a result of this seminar:

* The Ministry of Energy can set to work with industry and Ontario Hydro to identify potential cogeneration demonstrations, and can assess potential incentives that would encourage cogeneration.
* Ontario Hydro meanwhile can undertake to visit all potential users of industrial cogeneration to discuss in depth the issues raised over the last two days and to assess what assistance we might provide in specific cases.
* And, industry, consultants and manufacturers can give serious consideration to the formation of a joint venture development for cogeneration in Ontario.

A. Juchymenko

Opening Remarks

JAMES A. C. AULD,
Minister of Energy

It's a pleasure to be welcoming you this morning. In fact, it's a double pleasure. First, I believe this seminar on the industrial cogeneration of electricity is timely and I'm glad to see these two days of intensive study and discussion being started. But it's an added pleasure for us in the Ministry of Energy and in Ontario Hydro to find, by your attendance, how many top-level technical and economic specialists in Ontario industry are clearly interested in exploring the potential that cogeneration might hold for the future.

For the general public — unfamiliar with what cogeneration means — your discussions will also be providing a glimpse into the future, and an awareness that there are more means available to us to augment Ontario's sources of electrical energy than many of them had previously realized.

The Ontario Government's energy policy is to provide a climate encouraging the maintenance of a balanced supply of energy with due regard to its impact on the province's natural environment, and with a full recognition of Canada's limited resources of fossil fuels. Clearly, therefore, this policy includes encouragement of the development of alternative energy sources.

The subject matter concerning us for the next two days, industrial cogeneration, can be defined quite simply as the simultaneous production of steam for industrial purposes and electricity for one's own use — and possibly for sale to Ontario Hydro. In other words, industrial cogeneration offers an alternative energy source. It is in that light that I find it an extremely interesting and attractive concept well-deserving of the serious study it will be receiving at this seminar.

Indeed, to most people the idea of on-site generation of power, combined with the production and utilization of steam, hot water or hot air, makes so much sense in an energy-short world that they might well wonder what's been holding it back. Those of us here, of course, know that universal application of the concept isn't as free from other considerations as it may sound. But we also know of the many industrial situations in Ontario where the concept has already been applied.

It has the potential of making a significant contribution in assisting some major power users to regain their competitive edge by employing their own energy supplies more efficiently. In the pulp and paper industries, for example, it both solves a wood-waste problem and makes effective use of a fuel indigenous to the province. In the steel industry, energy can be recaptured from by-product gases.

Indeed, a recent survey indicated that already 39 industrial plants in Ontario have turned to cogeneration to save energy and money. These installations alone have a generating capacity totalling something of the order of 500 megawatts. This is roughly comparable to the needs of a city the size of London, Ontario. I understand that during this seminar you will be hearing of a subsequent study which found that if by-product power was being produced in all Ontario industrial steam plants in which such modification would be feasible they would generate about 2,000 megawatts — equivalent to the capacity of Ontario Hydro's Pickering 'A' plant.

In other words, by providing decentralized power generation across the province, cogeneration could reduce the pressure for growth on Ontario Hydro. If we look at West Germany — a country which has direct access to coal and a developing nuclear program — we find that 28 per cent of that country's total electricity generation is provided by industrial users.

That's an impressive figure. But before we can use it as a valid comparison, we must remember that by any international standard, the price we pay for electricity

in Ontario is still exceptionally low, while in Europe it is high. Indeed, industrial users in Hamburg, West Germany, paid 6.29 cents per kilowatt-hour, while their Ontario counterparts paid a 1977 average of 1.61 cents. That's a factor we must take into account, although we can't afford to assume it will be a constant one.

Economics, and the lessons we can learn from the experience of other countries that are dependent on relatively expensive imported fuels, constitute only two of the areas to be examined. There are others. But wherever we start, we soon find ourselves confronted by a paradox.

I find it ironic that while, intellectually and socially, we can recognize that industrial cogeneration is an idea whose time has come, it could be argued equally that this is the worst of times to be considering it. The best of times, the worst of times . . . I can understand the public's bewilderment at the apparent contradiction.

Our first task has to be to examine how it can be that, with so little doubt of the increasing future contribution it could make to Ontario's total energy needs, so many obstacles and objections appear to stand in the way of a significantly expanded industrial cogeneration program being undertaken by the private sector in Ontario.

First, of course, is the difficulty in understanding why a seminar to deliberate the introduction of industrially produced electricity into Ontario's energy mix should be held at a time when Ontario Hydro may be facing its largest reserve margin ever, and has already this year cut back its committed construction program by some 1,100 megawatts.

Second is the possible reluctance of the private sector to undertake the further capital investment attendant on cogeneration in plants which have already reduced their electrical demand by introducing energy conservation programs.

Third, you will hear some speakers at this seminar advocate natural gas turbines with heat exhausted to conventional boilers. This may seem a problem in itself, since any reasonable interpretation of statements by the petroleum industry and the National Energy Board two years ago, on the supply of natural gas for this purpose, would clearly have blocked consideration of such a proposal.

This is certainly a question to be resolved, but it can be noted that the National Energy Board is now reexamining the supply and demand of natural gas, and initial observations are very encouraging for the future supply of this fuel. The most appropriate use of natural gas is still an open question, however. It is interesting to note, though, that Ontario Hydro is taking two natural gas fired units out of service in order to reduce its use of this "perfect" fuel.

Fourth, something of a paradox in intself, is the fact that at this time, when we are examining how greater use can be made of cogeneration, the ratio of industry-generated electricity to total consumption in West Germany is reported to be rapidly decreasing. Price differentials might explain why cogeneration would initially grow faster there than in Canada, but it is hard to understand why cogeneration in Germany is now decreasing. An understanding of this occurrence needs to be sought.

And one point more: A few minutes ago, I defined industrial cogeneration as the simultaneous production of steam for industrial purposes and electricity for one's own use, *and possibly for sale to Ontario Hydro.* But the present basis on which Ontario Hydro purchases power is related to a pricing policy developed over many years, and must take account of the most efficient use of Hydro's own generating capacity. On this basis, it appears that the number of such purchasing contracts might be limited.

So I'm aware you have a good deal of digging below the surface to do at this seminar to identify the real roots of these problems before the explanation of the paradox is found. When you are looking at the possible costs associated with industrial co-generation of steam and electricity in relation to its development potential and its energy conservation potential, you will also have to consider whether the relatively low industrial rates Ontario Hydro now charges will continue into the next decade.

If you share my concerns about that, I think it follows that the potential benefits of industrial cogeneration must grow larger year by year. And, in that case, those factors that today may be slowing its development may actually provide us with the planning time we need to meet the future with greater confidence.

I will be looking forward to learning the consensus this seminar reaches with a great deal of interest. And I can tell you now that I am prepared to consider reasonable suggestions requiring legislative or fiscal action. I have a commitment to the efficient use of energy in all forms, and to securing the maximum practical value from Ontario's indigenous resources, and I mean to uphold it.

This is a two-day seminar. I am eager for a Day Three to be held — the day on which the Government of Ontario, Ontario Hydro and industry can say with confidence, "The long-term economics of industrial cogeneration are attractive; this is an option we can pursue together with vigour."

I don't know when that Day Three will arrive. But I do know this seminar marks a big step in its direction.

Future Fuel Availability for Industrial Cogeneration

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Ontario Ministry of Energy

There have been, from time to time, very low spot-market prices on heavy fuel oil. However, at this time there is no merit in assuming a continuation of distress pricing for heavy fuel oil, and these low prices should not stand in the way of conservation programs. This paper will review and compare the various alternative forms of energy, which will be available to Ontario industries in the future, as to their price, efficiency and availability of supply.

Perspective

I would like to review with you the future prospects for the fuels needed to continue to power Ontario's industrial sector, with special reference to cogeneration. The paradoxical situation surrounding electricity matters that the Honourable Mr. Auld has just described is quite consistent with the current sharply constrasting views of what the present energy situation is, and what the future holds for the Province's needs.

Based on the conflicting messages provided through the communications media by government, by energy suppliers and a host of real and professed experts, the public today should be forgiven for exhibiting what seems to be a schizophrenic point of view on energy matters.

This double-think surfaced in a very interesting consumer survey research report prepared for Ontario Hydro by Goldfarb Consultants. On the one hand, people indicated an inherent belief in technology and the energy resource wealth of the province and the country, but on the other hand they still have serious doubts and apprehensions about the future.

Those surveyed displayed a distrust of the energy industry to tell them the truth about the supply situation. As people are not sure what to believe about shortages, they expect that the industry is manipulating the situation to its own advantage. To illustrate some aspect of this schizophrenia, 68 percent of Ontario residents feel that conservation of energy should be close to or one of the highest priorities in the Province, yet concern about energy availability ranks thirteenth in a list of issues of concern, below unemployment, inflation, the economy, etc.

The Ontario Ministry of Energy, being concerned that a consistent, informed statement about supply be made available to industry users and the Ontario public on a regular basis will soon be publishing its first, "Ontario Energy Review." Ministry staff, virtually all of whom have many years of supply industry experience, meet regularly with the industry, the National Energy Board and the Alberta Energy Resources Conservation Board. "Ontario Energy Review" will report and interpret the energy scene for Ontario. My remarks are drawn in part from it.

Overview

On the assumption that through the National Energy Board, the Federal Government will continue to take an extremely careful and critical approach to the approval of crude oil and natural gas exports, we envisage that all fuels will continue to be available in Canada for at least the next ten years. This also assumes continued international stability and supply to the eastern seaboard. Beyond that period the availability of crude oil and natural gas will depend on exploration and development successes in the frontier areas of Canada, during this interim period, as well as on the development of the technology associated with extracting oil from oil sands and heavy oil deposits.

Over the longer term, coal is expected to become an increasingly important fuel source, both for direct burning and as a source of synthetic fuels. Figure 1 is intended to put the current production of Canada's fossil fuels into the context of the estimated remaining recoverable reserves. This is a very approximate representation but illustrates in a useful way that while we are not going to run out of fossil fuels in the foreseeable future, we will have to make fairly significant shifts in the way we develop, process and use the fuels available.

It is estimated that even with substantial conservation, Canada will have to invest some $180 billion (1975 dollars) over the next 15 years to help provide required

energy supplies and to move towards self-reliance. The magnitude and timing of such investments, which include multi-billion dollar projects such as the Alaska Highway Gas Pipeline, the Polar Gas Pipeline, In-Situ Tar Sand Recovery Plants and electric generating stations, suggest that strains on markets for capital and labour could result. Also, the external financing requirements associated with the $180 billion suggests that the inflow of foreign capital dedicated to financing energy projects will be in the order of $3.8 billion per year (1975 dollars) during the next 15 years, about one half of the total capital borrowed abroad by Canada in 1976.

One of the banks has revised the $180 billion dollar figure to something higher than $300 billion in current dollars. None of this expenditure includes the user investment to shift away from oil.

Future Availability of Coal

Canada's recoverable coal resources are, without doubt, enormous when compared, as an energy source, with remaining recoverable reserves of conventional crude oil and natural gas.

Deliveries of Western Canadian coal to Ontario Hydro, using the new Thunder Bay coal terminal, were initiated in 1978 and this supply is likely to meet 25% of Ontario Hydro's annual requirements by 1985, the remainder being supplied from U.S. sources. A recent review of Canada's coal potential south of the 60th Parallel estimated that there exists more than 80 billion tons of clean coal which is potentially available as an energy source competitive with the present price of oil, delivered to Ontario markets.

Of course, this BTU comparison of coal and oil does not reflect the additional costs associated with the use of coal, including efficiency considerations and environmental costs. It is an indication, however, that as crude oil prices continue their upward spiral not only will the available coal resource base expand but there will be an increasing number of uses for which coal will become an economically attractive proposition. The future price relationship between coal and its derivatives and synthetic oil from oil sands is not yet known.

As an example of the expansion of the resource base, consider the Alberta Plains coal. Currently only those reserves which are mineable by open pit methods are potentially available from an economic standpoint, but, if the real price of crude oil increases by more than 20%, we can expect that large quantities of coal that can only be obtained using underground mining methods will become economically viable. We also note the trend to increasing use of coal by Ontario's cement industry, in preference to crude oil or natural gas, as an indication of the improving economics of coal.

The growth in the supply of Canadian coal production will be tempered, not only by economic attractiveness, but also by the availability of manpower, machinery, capital, and the development of the transportation infrastructure.

Assuming a reasonable rate of growth within the Canadian coal industry, it is entirely feasible that interprovincial trade could increase from a potential capacity of approximately 8 million tons/year at the present to over 100 million tons/year by the year 2000.

New technology, currently in the pilot plant stage in the U.S. and Europe, and coal conversion studies underway in Canada, could have a big impact on the rate of development of the nation's coal resources. The successful and economic conversion of coal deposits into clean burning solid, gaseous and liquid fuels is likely to be demonstrated under a wide range of operating parameters over the next decade. Fluidized bed combustion could also result in large increases in the demand for coal, although, at the moment, I do not know of any commercially successful, operating unit above 39 megawatts of thermal capacity. Canada's first experiment with this new technology is planned to come into operation in 1980 using a 5Mw boiler at Summerside, Prince Edward Island.

The late Robert Costello, a member of the Royal Commission on Electric Power Planning, advocated piggy-backing of Ontario industrial needs for thermal coal on Ontario Hydro's unit train operation from the west. He felt that by integrating both the transportation and the contractual needs of industry with Hydro, the economics for industrial cogeneration could be substantially improved.

Future Availability of Natural Gas

From a review of the material submitted to the current National Energy Board hearing on Natural Gas Supply and Demand in Canada, it is obvious that opinions and estimate reserves vary widely — so widely in fact as to stretch the bounds of belief — and one is tempted to conclude that some estimates are clearly self-serving and should be dismissed on that account. For our part, the Ministry has great confidence in the professional capabilities and experience of the Alberta Energy Resources Conservation Board and we believe that its advice should be given very serious consideration.

Clearly, too, because the Ontario market represents more than half of Canadian natural gas demand, the Province must be concerned with the security of natural gas supply. That is why Ontario has proposed to the Board a formula for reviewing natural gas export applications which sets aside in Western Canada proven reserves to supply the domestic market for 25 years, and ensures deliverability to meet domestic demand for at least 10 years.

Let us review the Alberta forecast of that province's future natural gas supply since this is where 99% of Ontario's natural gas consumption originates.

The ERCB of Alberta estimates that at the end of 1977, from an initial proved reserve of 83 Tcf, there were proved remaining recoverable reserves in Alberta of 58 Tcf.

The Board conservatively estimates the ultimate potential of Alberta to be 110 Tcf and on this basis concludes that additional removal permits can be issued, within the next four years, amounting to 14 Tcf.

The current Alberta production rate is approximately 2.3 Tcf/year and this could be increased to 3.1

Tcf/year in the period 1982 to 1984. The productive capacity is then expected to decline gradually reaching 2.2 Tcf/year by 1995.

With an ultimate potential of 110 Tcf, it is expected that Alberta gas production will meet all the demand from the rest of Canada as well as existing export commitments until the period 1985 to 1988. At some point in that period the application of Alberta's rolling 30-year protection formula will result in a halt to the granting of additional removal permits. This will have an immediate impact on Eastern Canada.

If the ultimate potential in Alberta is 130 Tcf, then that province would be able to meet the demands of the rest of Canada up to the 1992/1995 period. Some industry sources claim that the ultimate potential of Alberta is 180 Tcf or more.

The graph shown in Figure 2 illustrates the range of possible natural gas production from Alberta. Depending on the ultimate potential, 110 Tcf to 130 Tcf, it also shows the magnitude of the excess production capacity and the impact of the application of Alberta's protection policy. Some additional time before a production shortfall occurs is suggested by the fact that the later market growth figures, here depicted by Trans Canada's forecast, are somewhat lower than those used by the ERCB.

Eventually, the conventional gas supply from Alberta may be replaced by supplies from the Mackenzie Delta, Beaufort Sea, Arctic Islands and other frontier areas as well as from the gasification of coal. While there is little doubt that very substantial natural gas reserves exist in the frontier regions of Canada, it is also apparent that there will be long lead times required to find, develop and transport these reserves to markets. The staggering costs have already been discussed.

In summary, natural gas from Alberta is certain to be available to all existing and new consumers up to 1985. At that time, or shortly thereafter, there is a strong possibility that Alberta will close the door on further removal permits, and from then on it will become more and more difficult for any new users to get assurance of long-term supplies until substantial frontier reserves are connected to markets. While we expect such reserves will eventually be available, there may be a period of temporary shortages because of the very high costs associated with such supplies and the uncertainty associated with the exploration program. It all depends on the average field size and accessibility of these reserves. Until they are discovered, it is anybody's guess as to the actual timing of such deliveries.

In view of this prospect, it is vitally important that we question the advisability of increased natural gas exports and of expansion of the transmission system to the eastern seaboard from the conventional gas supply areas of Western Canada at this time.

Future Availability of Oil

The availability of heavy fuel oil for industrial uses depends on the crude oil supply to the refineries.

Currently, the world and Canada has a surplus of heavy fuel oil production from refineries and crude oil production is below capacity. This has resulted in fiercely competitive marketing in Ontario against natural gas for those customers that have dual-fuel capability. What is needed is a study of the rationalization of the refinery capacity, the grades run and the markets available in central and eastern Canada and the north-eastern United States. To this end, the Council of Provincial Energy Ministers have asked for (are setting up) an industry and government task force to make recommendation in this area. It is our expectation that the distress pricing of heavy fuel oil will not last, and these low prices should not stand in the way of conservation programs. A guaranteed long-term supply of heavy fuel oil for any particular incremental purpose such as cogeneration will be hard to come by. It is unlikely that any supplier will commit to such an obligation for an extended period when there is every likelihood that all available oil will find a ready market, and when the refineries have little control of their own future crude oil supply.

The National Energy Board recently issued its cautiously optimistic report on oil supply and demand in Canada and concluded that there will be sufficient indigenous production to supply west of the Ottawa Valley until 1995; light crude exports could be maintained at the current 55,000/bbl/d level until the end of 1981 and heavy crude oil surplus to Canada's own needs could be exported throughout the period to 1995.

The following table summarizes the new report:

	(000;s Bbls/day)		
	1985	1990	1995
Domestic Demand	2049	2157	2297
Potential Producibility	1289	1331	1392
Net Import Requirement	760	826	905

Ref: National Energy Board, September 1978.

The critical question therefore is the availability of world crude oil. In addition, however, even if the world price of oil does not increase, Canada's balance of trade in oil could swing from what was a surplus of $1.0 billion in 1975 to a deficit of several billion in 1985.

We sense a continuing shift in Ottawa away from any hope for self sufficiency in oil across Canada. The new federal position is to attain self-reliance in oil west of the Ottawa Valley, including Montreal, and toward this end to move natural gas to the eastern seaboard.

There have been a number of studies into world crude oil supply and demand with wide variations in the timing of the expected shortage; the more cautious observers feel that this situation could arise in the first half of the 1980's while more optimistic analysts consider that this may not occur until the 1990's or even later.

Recent developments in Alaska, the North Sea and Mexico, and the slowness of economic growth generally, have brought about a temporary surplus of world

crude oil. However, it is apparent that the world is using up known reserves of economically accessible oil faster than new supplies are being found.

The highly regarded independent petroleum geologist, M. King Hubbard, provides an interesting graphical depiction of this in his report to the United States Congressional Research Service, Library of Congress, 1977. Congress had asked Hubbard to estimate not only the reserves found to date, but just how much might be expected to be discovered in total. As the graph shows he found that the world has already discovered about one half of all the petroleum resources that were ever laid down throughout time. One immediate reaction is that, "Well, that means that although we have used a lot, there's a lot more to be found and developed."

James Schlesigner recently put this in perspective by stating that to meet the future world demand we would need to find an Alaskan North Slope every six months, a North Sea every year or a Kuwait every three years. His conclusion was that this is just not going to happen.

Figures produced by Energy, Mines and Resources, Canada indicate that tightness in the world supply of oil could arise as early as the mid-1980's, but a key factor is the volume which Saudi Arabia will be able and willing to produce.

Whatever forecast one is inclined to, the supply is obviously limited and sooner or later in this century consumers will be bidding against each other for the limited world supplies.

In conclusion, Canada will continue to be dependent on imported crude oil up to the mid-1980's, when there could be substantial instability in the world oil market. Beyond that period, domestic oil supplies will depend on the success we have in the development of the substantial deposits of oil sands, heavy crude oil and on frontier areas.

Because of the world supply difficulties that could arise in the 1990's, crude oil is likely to become a high priced premium energy resource rather than the price leader it is at the moment. Its use will be more and more confined to those areas where there is no ready substitute such as in the transportation field.

Future Availability of Renewable Resources

Significant amounts of forests, agricultural, municipal and industrial wastes are produced each year in Ontario. This material represents both an environmental disposal problem and a potential energy source.

Ontario's biomass resources potentially available for fuelling cogeneration are summarized in Table 2. Leaving out the most expensive one-third of the forest residue resource, there is a total potential to produce about thirteen million tons per year of renewable feed stock. This is equivalent to an annual energy production of 90 x 1012 BTU or about seven percent of Ontario current annual oil requirements. This potential includes the use of about one million acres of poplar plantation to produce about 1½ percent of Ontario's annual forecast oil requirements in the year 2000. Not included are the agricultural residues, animal manure, grain corn residue and cereal straw, totalling some 10 million oven dried tons annually which are not relevant to cogeneration.

Steam-electric production from agriculture and forest residues such as sugarcane residue and hogged wood waste is established commercial technology in the United States. Many of the existing plants are designed to burn fossil and non-fossil fuels, either simultaneously or separately. According to a recent U.S. survey of installations that generate their own power, pulp and paper mills burn 46 percent wood derived fuels and 54 percent fossil fuels, while forest product mills burn 98 percent wood fuels and 2 percent fossil fuels.

At this time, only 50 Mw of electrical power are currently derived from wood wastes in Ontario.

There is an enormous spread in costs for biomass resources, depending upon whether or not some of the costs can be internalized to other industrial processes. The industrial cogeneration opportunity at Hearst, to be discussed at another session, is a case in point. There it was assumed that the delivered cost of wood residue was $2.00 per ODT. By contrast, the Ontario Ministry of Natural Resources has estimated that larger amounts would be available in the Bancroft and Thunder Bay areas, but at a substantially higher cost. For example, 825,000 ODT of wood per year would be available in both Bancroft and Thunder Bay at an estimated average cost of $33.00 per ODT.

Cogeneration Choices

Before I conclude, I would like to contrast the fuel flexibility of the traditional approach and the rivaling industrial combustion turbines for producing heat and by-product power. In the traditional approach, the steam and pressure conditions are established in the boiler. Provided that satisfactory economic conditions prevail, steam can be throttled through a turbine, independent of course, of fuel type.

Alternatively, fuel oil or natural gas can directly fire an industrial-scale combustion turbine to produce electricity and raise steam in the exhaust circuit. In view of my remarks on the changing fuel supply scene, while fuel flexibility is important, I would not want to discourage serious consideration of the combustion turbine technology for new installations. Indeed, I am informed that a new turbine is being developed that will even accept wood chips in the feedstock.

Conclusion

The conclusion, then, is that our energy future has improved over the last three years. And while costs will go up dramatically, our alternative options are improving.

The Ministry and Ontario Hydro will work to open up some of these options for Ontario industry, and in particular, will see that industrial cogeneration gets the fair and critical assessment that it is due.

Discussion:

Future Fuel Availability in Ontario for Industrial Cogeneration

DR. IAN ROWE
Ministry of Energy

Question: Gordon Robb, *Federal Department of Energy, Mines and Resources*

Has Ontario considered peat as a fuel for co-generation? Both Quebec and New Brunswick are looking at this, and the Consolidated Bathurst Pulp & Paper Company has looked at it as an industrial boiler fuel.

Answer: Dr. Rowe

The Ministry of Natural Resources is in the process of looking at both the peat and at the lignite opportunities in Northern Ontario. The problem of peat, of course, is one of getting the product to where you need it and getting rid of the water and so on, and that is not a small task.

Survey of Costs Associated with Industrial Cogeneration in Ontario

DONALD D. DICK
Dick Consulting Services Ltd.

The Load Management Department within Ontario Hydro had initiated a comprehensive study to collect data on the existing industrial cogeneration installations, to determine generating costs associated with these installations, to estimate capital costs of new installations and to estimate the potential for industrial cogeneration in Ontario. This study has been completed and the findings are discussed below.

Introduction

Ontario Hydro commissioned Dick Consulting Services Ltd. in September 1978, to carry out a survey of costs associated with the cogeneration of electricity in ten industrial establishments. This work was the continuation of an earlier study made by Acres Shawinigan in October 1977.

This paper deals with the identification and documentation of costs associated with a total of fifteen industrial plants including five covered by the Acres Shawinigan report.

Data Collection

The data in this report was developed from information collected from industrial companies by means of a questionnaire and plant visits. During the course of the study, sixteen companies were invited to participate; five declined and one was no longer eligible, having removed their power generation equipment several months previously.

The initial contact with each company was by means of a letter written to either the president or a senior officer. Each letter was followed up by a telephone call with the intent of arranging a plant visit.

In order to ensure that the information collected remained confidential and anonymous, a code number was assigned to each company. The first two numbers denote the industrial classification, and are followed by a sequential number.The code numbers are as follows:

Food and beverages:	*10.2
Pulp and paper:	*27.2; 27.3; 27.4; 27.7; 27.8; 27.9; 27.10
Iron and steel:	*29.1; 29.3
Industrial chemicals:	37.2; *37.3; 37.4
Mining:	50.2; *50.3

*Indicates those companies covered by the ASL report. (Acres Shawinigan)

The questionnaire sought the following information:

- boiler data including number of units, steam flow, steam conditions, annual operating hours;
- steam turbine data including number of units, annual generation, steam conditions entering and leaving, steam flows;
- load duration curve, energy purchased, demand purchased;
- fixed costs on capital
  - interest rate charged on capital employed before taxes
  - depreciation
  - economic life
  - interim replacement costs
  - insurance
  - taxes
- variable operating costs excluding fuel
  - operating labour
  - supplies and materials consumed in normal operation
  - administration and overhead
  - maintenance material and labour
- salvage fuel costs (internal costs charged by company for kraft mill black liquor, bark and sawmill residues)
- purchased fuel costs

The major problems encountered in the collection of data were as follows:

a) repeated delays were often experienced in obtaining decisions from companies' managements as to participation in the survey;

b) delays due to plant strikes which occurred at two of the plants;

c) difficulty for industrial plant personnel to find time to collect the information requested;

d) during the course of the study, personnel changed in some of the plants, resulting in discontinuity;

e) lack of uniform accounting procedures among the companies.

Analysis

The method of analysis involved the calculation of the cost of electric power generation within each company in terms of mills per kilowatt hour. This composite mill rate is made up of the costs of operation, maintenance, fuel and capital repayment charges. Wherever possible, the calculated mill rate was compared with that submitted by the company; unfortunately, few companies have such a figure available. The calculations were sent to each company with a view to obtaining their agreement and/or comments.

The composite mill rate was also calculated for each company on the basis of electric power generation in a hypothetical new plant of similar capacity to the existing one, using current capital costs. The fuel and operating costs that were obtained from each company, pertaining to their existing plant, were used over again in this calculation.

The current capital cost for replacing each existing plant was calculated to reflect the incremental cost of the boiler plant attributable to power generation, and included the total cost of replacing the steam turbine generator facilities.

Equipment suppliers co-operated in the study by providing current prices for the turbines and boilers of similar capacity and steam conditions to those in the existing plants. They also supplied prices for low pressure boilers which were sized to supply only the existing process heat loads.

The current capital cost for replacing that portion of the existing plant attributable to cogeneration was calculated as the sum of the following items:

a. Incremental boiler costs = high pressure boiler costs minus low pressure boiler costs.

b. Incremental boiler auxiliairies = 35% of incremental boiler cost.

c. Turbine generator = total quoted.

d. Turbine generator auxiliairies = 35% of turbine generator cost.

e. Civil, structural work = 10% of the sum of a, b, c. and d.

f. Contingency, engineering, administration, construction overheads, profit = 35% of the sum of a, b, c, d and e.

The capital recovery factor was calculated using the same formula as ASL, namely,

$$\frac{i}{(1+i)^{tx}-1} + 0.01 + 0.01$$

where i = rate of interest before taxes
tx = economic life

It was assumed that the economic life and the useful life would both be 30 years; the annual cost of interim replacement was assumed to be one percent of the capital cost, and likewise for insurance and taxes. The rate of interest used in the calculation was 10%.

The calculations used to obtain the mill rates treat the financing of a cogeneration project in the same manner as would a public utility. Although these rates provide comparative costs for generating electrical energy from each company's steam turbine generator sets, they do not indicate the potential for cost savings on purchased power, nor the Discounted Cash Flow (D.C.F.) rate of return on the investment on an after tax basis for an industrial company.

In order to determine if an investment in cogeneration by each company could be justified at today's costs, D.C.F. rate of return calculations were made based on the capital required for a current replacement of the existing plant. The fuel costs and operating costs reported by each company were used in this calculation.

The gross savings in energy costs were calculated by applying the unit cost of purchased energy against the annual power generated by each company. The gross savings in the public utility's demand charges were assumed to be the maximum output of the turbine generators, multiplied by the utility's demand charges. Where the maximum output of the turbine generators was not supplied by the company, it was assumed to be the full capability of the condensing turbines plus the power from the non-condensing turbines when supplying the maximum process heat load.

A capital cost allowance of 50% was applied on the assumption that the entire investment would be Taxation Class No. 8; the economic life was assumed to be 30 years.

Results

The composite mill rates have the following ranges:

	Existing Plant	Replacement Plant
Capital repayment:	0.41 to 3.83	5.62 to 74.98
Fuel:	3.43 to 30.30	3.43 to 30.30
Operating and maintenance:	1.50 to 71.04	1.50 to 71.04
Composite mill rate:	7.50 to 98.30	16.90 to 173.32

On the basis of receiving an adequate return on the invested capital, only three out of fourteen companies would be able to justify a cogeneration project. This statement, of course, hinges on the accuracy of the fuel and operating costs provided by each company — which are very questionable in many instances.

As would be expected, most of the companies showing the highest returns on their investment in cogeneration utilize a high proportion of internally generated salvage fuels in place of purchased conventional fossil fuels.

It was found that many of the cogeneration facilities were originally installed for reasons which are now less valid, due to changes that have since taken place in manufacturing operations. Some examples follow.

Company 27.7 originally installed two condensing turbines in order to obtain sufficient power supply in their remote location. These units have such a

The industry breakdown is as follows (in mills/kwh):

	Food & Beverage	Pulp & Paper	Iron & Steel	Ind. Chemicals	Mining
Capital repayment existing plant	0.45	0.56 to 2.81	3.83	0.05 to 0.23	0.41 to 9.96
Capital repayment replacement plant	17.45	7.27 to 13.57	24.34	7.67 to 74.98	9.96 to 28.11
Fuel	5.55	4.92 to 8.99	4.40	3.43 to 30.30	2.80 to 13.09
Operating and maintenance	1.50	2.18 to 6.92	14.27	7.05 to 71.04	5.41 to 11.08
Composite mill rate existing plant	7.50	7.66 to 16.14	12.70	18.40 to 98.30	24.56
Composite mill rate replacement plant	24.50	16.90 to 25.50	43.00	24.20 to 173.32	18.91
D.C.F. rate of return %	8	0 to 12.5	0	0	0 to 2
Number of companies sampled	1	7	1	3	2

high heat rate that their operation is sub-marginal.

Company 37.2 installed a turbine generator set many years ago for the purpose of generating D.C. power. Today, their D.C. power requirement is reduced to the point that the turbine operates at a very low load factor and is submarginal.

Company 27.2 reduced its process heat load since installing cogeneration facilities, resulting in submarginal returns.

Reasons for other submarginal cogeneration operations are given below:

Company 37.4 suffers from high fuel costs; consequently, they use their turbine generator set to control peaks and for emergency power.

Company 27.9, although having a low heat rate, has high fuel costs, reflecting the fact that their process and raw materials are unable to produce salvage fuel, unlike other companies in this industry.

Company 27.4 has their turbine generator set providing the complete process heat load to one unit of their plant which directly limits its output. Furthermore, this turbine receives steam generated only from purchased fossil fuel, which is relatively high priced.

Company 50.2 base loads the back-pressure turbine generator which receives steam generated from waste heat. The condensing turbine is used to control power peaks; however, since insufficient waste heat is available, purchased fossil fuels are required for this purpose.

The companies that are equipped with modern facilities integrated with the combustion of salvage fuels enjoy a reasonably high return on their investment in cogeneration. Companies 27.8 and 27.10 are excellent examples of well devised plans for the profitable use of cogeneration.

Conclusions

1. An examination of the plant facilities, load factors and processes leads to the conclusion that each cogeneration facility is largely unique and specific. As a result, comparisons between companies, even within the same industry, can be distorted because their processes are often different. Such differences are reflected in the capital replacement costs, operating costs and load factors.

2. It is obvious that the allocation of costs within each company's operation is different and possibly done on an arbitrary basis in many instances. As a consequence, comparison of cost figures between one company and another, even though they may be in the same industry and utilizing similar processes, is not necessarily valid.

3. The unit capital cost of replacing the portion of the existing plant capacity attributable to power generation varies widely. It is largely dependent upon the sophistication of steam generation equipment required to utilize salvage fuels obtained from the plant process, the process heat loads, the plant load factors, the characteristics of the salvage fuel, and other factors which can be described as unique and specific for each plant.

4. It was hoped at the commencement of the study that it would be possible to obtain costs of generating power from units of specific size. Due, however, to the combination of equipment sizes, it was not possible to segregate out a wide selection of costs per unit size of equipment.

5. If it had been possible to obtain more precise data in regard to electric peak demand and process heat load demand on the same time scale, it might have been possible to select replacement plants that would be more efficient than the cogeneration systems installed in the existing plants. Unfortunately, such information was either not available or could not be made available to meet the schedule for preparing this report.

Acknowledgments

We gratefully acknowledge the assistance that we have received from the equipment suppliers, particularly ASEA Limited, Babcock & Wilcox Canada Ltd., Canadian General Electric Company Limited and Foster Wheeler Limited; Acres Shawinigan Limited for permission to use material from their report dated April 19, 1978; the Load Management Department of Ontario Hydro for their helpful suggestions; and the participating companies and their staffs who made this study possible.

TABLE A COMPOSITE MILL RATES

All figures are in mills/kwh

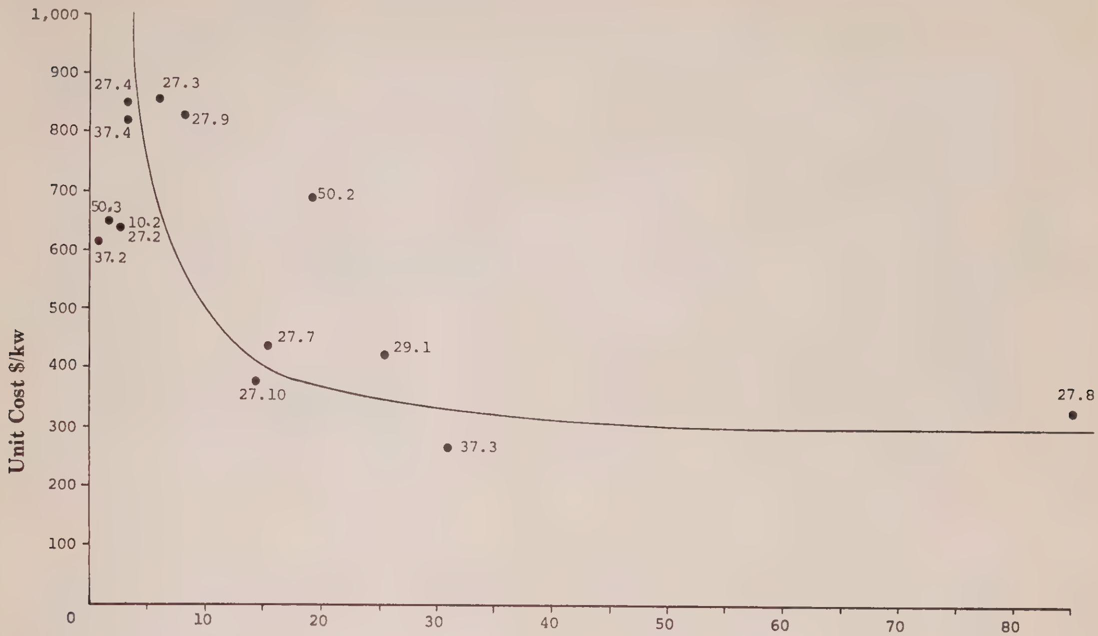
Company No.	Fuel	Operating	New Plant	Existing Plant	Reported Mill Rate
	Calculated Mill Rate				
10.2	5.50	1.50	24.50	7.50	-
27.2	9.15	2.77	25.50	12.70	-
27.3	8.50	2.87	22.99	11.37	-
27.4	8.99	6.49	21.10	16.14	-
27.7	7.62	6.92	22.51	14.54	16.83
27.8	7.14	2.49	16.90	10.22	7.56
27.9	6.53	3.47	21.30	12.81	12.48
27.10	4.92	2.18	18.90	7.66	5.78
29.1	23.90	4.40	43.00	32.17	-
37.2	27.30	71.04	173.32	98.30	110.50
37.3	3.43	13.07	24.20	18.40	-
37.4	30.30	7.05	82.70	37.58	-
50.2	13.09	5.41	46.61	18.91	18.91
50.3	11.80	2.80	24.60	-	-

TABLE B D.C.F. RATE OF RETURN

Company No.	Overall Heat Rate Btu/kwh	Composite Fuel Cost $/10^6Btu	Portion of Total Energy From Boilers Used for Power Generation %	Capital Cost Replacement Plant $000	Unit Capital Cost $/kw	After Tax D.C.F. Rate of Return %
10.2	4,525	1.49	8.6	1,600	640	8
27.2	4,862	1.43	13.0	1,600	640	2.5
*27.3	3,880	1.23	4.0	5,190	865	2
27.4	5,960	1.51	5.1	2,570	857	-
*27.7	13,069	0.99	19.1	6,650	430	-
*27.8	4,230	1.26	14.8	26,920	320	8
27.9	3,571	1.83	6.1	6,720	840	2.5
*27.10	3,600	0.39	5.5	5,490	378	12.5
29.1	14,259	1.42	40.7	10,640	426	-
37.2	10,000	2.72	2.1	620	620	-
37.3	6,111	NA	5.3	8,200	268	-
37.4	16,224	1.87	9.2	2,500	800	-
50.2	5,982	1.29	6.1	12,990	692	2
50.3	3,552	2.31	9.1	1,040	650	-

NA Not available
- Negligible return
* Companies that utilize salvage fuel along with conventional fossil fuels.

FIGURE 1 UNIT CAPITAL COST PER REPLACEMENT PLANT



Installed Replacement Capacity 1,000 kw

Discussion:

The Survey of Costs Associated with Industrial Cogeneration in Ontario

DONALD D. DICK,

President,

Dick Consulting Services Ltd.

Question: Gerry Lewarne, *Morris Wayman Limited*

For your DCF calculations what discount rate did you use?

Answer: Mr. Dick

We used 10% after tax. We simply used a 50% capital recovery factor. In other words you could write it off under taxation Class #8 on an after tax basis.

Question: Mr. Lewarne

We have done some calculations as well and we found that with the 10% after tax calculations vs financing by a company such as Ontario Hydro, there is a difference in mill rate of somewhere between 35% and 40% on a significant range of electrical output, and that seems to be the most important point that we have come up with. Did you consider that at all?

Answer: Mr. Dick

Yes. That is exactly true. You see the mill rate that was calculated there was simply a sinking fund, getting your money back at 10% over a 30 year life of the plant. This is perhaps not realistic as far as industry financing it, but it might be realistic as far as a utility is concerned.

Question: Gordon Robb, *Department of Energy, Mines and Resources*

One of my responsibilities at EMR is keeping tabs on the fuel used to generate electricity, and we see the Statcan questionnaires which ask how much fuel is used by industry to generate electricity. From this it is clear to us that many plants are not doing a

good job of allocating fuel to cogeneration, that is allocating as between the fuel and the process steam. I'm also a member of the Energy Committee and the Steam & Power Committee of the Canadian Pulp and Paper Association. We've explored this there also, and developed a method which, in the case of a non-condensing turbine, is just a matter of allocating steam heat equal to 3413 plus the turbine generator losses, which would be 3600, 3800 BTU's per kolowatt-hours steam heat. All our discussions indicate this is a much better approach than trying to measure steam flows and use ethalpy differences. I think people can produce very erroneous results that way. Then you divide the steam heat BTU's per kilowatt-hour by the boiler efficiency, or the efficiency of conversion from fuel to steam heat, and you have a figure that can't be far off, and all you've had to measure is the electrical output. If its an automatic extraction condensing turbine, the other measurement would be the condensate flow, you then allocate something slightly under 1,000 BTU's per pound of steam condensed, also to power, and in that way you get a fairly accurate result. Did you find that the people were doing a fairly good job of this, or did you find it a problem in your study?

Answer: Mr. Dick

We found that it varied throughout the industry, but we did exactly what you are saying wherever we could. We actually took readings across the turbine and we looked at it several different ways and it varied from company to company; what you could get, how much measurement you could make, and what kind of records they had and so on. But you are quite right that this is a very good way of doing it, but it is not always possible in the time frames and with the company's blessing.

Cogeneration Potential in Ontario and the Joint Venture Approach

A. JUCHYMENKO
Ontario Hydro

The realization of industrial cogeneration potential in Ontario will depend on the way the constraints are removed. It is believed by many industrial executives that this can only be accomplished by a private enterprise together with government assistance. This paper will look at various approaches to this problem and its associated costs.

This morning I would like to discuss with you the factors affecting the development of co-generation in Ontario, to review the recent trends in the U.S. and to describe one method of developing some of the available industrial cogeneration capacity.

As you well know some industrial operations have initiated programs for the conservation of energy, in order to reduce the impact of the recent energy price increases on the cost of their products. Both the government and Ontario Hydro have emphasised industrial cogeneration as an instrument of conservation of energy. As a result, cogeneration is starting to receive a considerable amount of attention from the industries that have some of the necessary technical and operating characteristics.

However, not many of these establishments are likely to undertake capital projects to reduce this impact. This is best indicated by the results of studies which showed, that in the first flurry of energy conservation activities, Ontario firms reduced their consumption by about 4 percent (1972 base), but have since moved very cautiously, particularly when capital costs were involved.

A recent study of the industrial market in Ontario conducted by Ontario Hydro revealed that at the moment, more than 15 feasibility assessments are being made within industry, with some projects in the 50,000 kw range. These are being done by industries which use a significant amount of both electricity and process heat, such as the chemical, petroleum, paper, steel, food, and rubber industries. The potential for industrial cogeneration in Ontario in these industries is estimated by various investigators to be between 700 and 2000 mw of electricity over the next 10 years.

The extent to which this potential will be realized is influenced by such factors as the cost of purchased power and fuel, and the financial viability of the cogeneration investment.

Although the potential for industrial cogeneration in Ontario is considerable, its realization is inhibited by technical, economic and institutional constraints.

(A) Technical Constraints

Each industrial plant has its own specific requirements for steam and electricity. Because of variations in the operating conditions, or because of low requirements for process energy, many plants lack the necessary characteristics needed for an industrial cogeneration plant. Plants which are the most technically suitable for industrial cogeneration are those with a high load factor for both the steam and the electrical requirements.

A survey, conducted by Leighton and Kidd Ltd. for The Porter Commission in 1977, identified a total of 268 existing stationary steam plants in industrial and institutional complexes, with an individual capacity larger than 40,000 pounds per hour. A steam flow upwards of 40,000 pounds per hour offers a potential for the production of about 2,000 kw of electricity. Most of these plants do not meet the technical requirements needed for an economic industrial cogeneration system. However, in a review of the individual returns of the above survey, 98 industrial plants were identified as possessing the necessary technical factors for industrial cogeneration, with an estimated total generating capacity of 1400 mw, some of which is already developed. This group of potential cogeneration requires a closer look. According to the Leighton and Kidd Survey, only thirty-nine plants have turbine generators, of which only 22 have units larger than 1000 kilowatts, for a total installed generating capaci-

ty of about 500 mw, representing about 2.5% of Ontario Hydro's installed capacity. Similar percentages are reported for the United States. In contrast, in West Germany, about 30 percent of total electrical generation is installed in industrial plants. It is obvious, then, that Europe is ahead of North America in this area.

(B) Economic Constraints

Another important factor to be considered is the *cost* of installing and operating an industrial cogeneration facility. In many plants in Ontario, this type of investment is not considered financially feasible because other investments, which have a higher return (ROI), compete for the capital budget of a given firm, and make industrial cogeneration projects seem unattractive. Out of the 98 plants having suitable technical conditions for electricity generation, our estimate is that only about 43 plants, capable of generating about 720 mw, have the necessary economic factors to make them financially feasible under the current conditions.

Generally, to day industrial establishments do not invest in cogeneration, except in cases where plants have by-product fuels which they can burn to produce steam and electricity, since fuel represents about 70% of the total direct cost of cogeneration. All other installations which must purchase fuels on the open market are not in the position to generate their own power, without financial assistance. While some assistance for cogeneration projects is available, in the form of loan guarantees and accelerated capital allowance write-offs, this assistance is not sufficient to overcome the ROI investment threshold, which is about a three year pay-back period for most industries.

Although the barriers to cogeneration are significant, many industries have overcome them in the past and some are currently assessing the economics of this method of meeting some portion of their electrical requirements. Our studies show that if a company accepts a pay-back period of seven years, then the overall saving in their electrical bill can be as high as 30%.

(C) Institutional Constraints

Regardless of the economics of industrial cogeneration, some Ontario industrial establishments do not consider electrical generation as part of their business and therefore would not invest in it. The executives of these organizations point to the shortage of trained personnel required to operate the boiler rooms, and to the absence of local maintenance organizations capable of speedy repairs.

In the U.S., on the other hand, many of the economic, fuel supply and regulatory constraints are producing the conditions that make cogeneration much more attractive as an investment alternative.

As a result extensive research and study is being done by government and industry, and nearly every major U.S. utility is studying the potential for cogeneration in its service area. For example, Southern California Edison has identified 39 viable projects, with a total capacity of 612 mw, and joint venture agreements have already been drawn up for at least one-third of these. Furthermore, the New York Power Pool, as part of an extensive study of cogeneration, has established a task force to do the following:

1. Conduct comprehensive research,
2. Estimate the cost of various cogeneration facilities as a basis for making economic comparisons,
3. Determine whether cogeneration would be feasible and economical, and
4. Identify the large fuel users in the state to determine whether any of these users may be likely candidates for cogeneration.

A number of large-scale studies have produced estimates of significant potential for cogeneration. The conclusions of four of these studies prepared for the U.S. department of energy indicated that:

1. Cogeneration potential in the U.S. is estimated to be between 6,000 mw without government action to 16,000 mw with government incentives,
2. As much as two million barrels of oil per day could be saved by the year 2000 with cogeneration, and
3. Electric utilities could save $2 billion to $5 billion in capital investments.

The common vehicle for cogeneration development in the U.S. is joint ventures between utility and industrial customers. San Diego Gas and Electric Co. has set up a subsidiary, Applied Energy Inc., to work with customers to establish joint venture systems, and to date, this company has developed 58 mw of cogeneration capacity. As well, Southwestern Public Service, Eugene Water and Electric Board, Gulf States Utilities' Systems, Consumers' Power Co. and others have also been promoting the joint venture approach to industrial generation of electricity.

This approach is being used because

a. It allows the utilities to circumvent the stringent regulatory constraint applied to operating and pricing practices currently imposed on them by the government,
b. The rate of return on their investment appears to be attractive when compared to their normal utility business,
c. Factors, such as the lack of expertise and the requirement for a significant capital commitment, which represent obstacles to most industrial companies considering cogeneration are effectively overcome as the utility can provide both, and
d. Depending on the balance between steam and electricity requirements, surplus electricity can be sold through the utility.

Possible Methods for Promoting Cogeneration

In Ontario there are a number of alternative approaches to promoting cogeneration in industry, in addition to the incentives already available.

These include:

- Some form of cost sharing of the capital costs,
- The utility supplying some of the turbine and generation hardware, at a nominal price and
- A joint venture agreement between the utility and the individual customer similar to that of the U.S.

Of these, the joint venture approach, as indicated from the trends inthe U.S., appears to have the most potential, as it overcomes the major investment and operational obstacles perceived by industry in considering cogeneration. As well, the alternative approaches make it more difficult to ensure that the cogeneration facility is operating at optimum levels and providing the economies of scale.

However, this approach cannot be implemented in Ontario since the Power Corporation Act of Ontario does not permit Ontario Hydro to undertake this type of investment. Regardless of these and other limitations, our preliminary analysis indicates that a private company could be established to promote cogeneration in the industrial field, and that this company would be economically feasible without Ontario Hydro's financial support.

A. The Nature of the Firm

For the purpose of this paper, this utility will be called Industrial Cogeneration Services Ltd. (ICS)

ICS Ltd.'s prime mission would be to market a complete cogeneration package to industry effectively, as a turn-key operation. The services that ICS Ltd. would perform for its customers and partners in developing cogeneration capability would be

1. To undertake a preliminary analysis of the technical and financial feasibility of an installation,
2. To arrange the necessary outside financing for the project,
3. To manage, design, purchase and install the necessary plants and equipment,
4. To operate the power plant,
5. To maintain the equipment,
6. To negotiate the purchase of fuels, equipment and spare parts

In marketing a cogeneration package, each cogeneration facility would be treated as a separate utility and a unique corporate entity. The user or customer of this utility would be an equal partner in the joint venture and his equity contribution would be the existing power plant. ICS Ltd. would match the equity contribution, and then negotiate the necessary additional financing to upgrade the power plant to have a cogeneration capability.

The on-site manning of a steam plant is defined and regulated by the Ontario Department of Labour through the Operating Engineers Act. ICS Ltd. would be responsible for the training and supervision of the on-site staff.

Although the power plants are very reliable and do not require continuous maintenance, a central maintenance organization would be maintained by ICS Ltd. This group would be responsible for all the cogeneration units and perform all the necessary major repairs and over-hauls. As this maintenance crew would be centrally located and would perform on-site maintenance on a scheduled basis or as indicated by the automatic monitoring systems, they would be effectively and efficiently utilized.

In marketing 'turn-key' cogeneration facilities, each unit, while having some unique characteristics, would be standardized in its boiler and turbine design and operation. Through standardization, spare parts and equipment would be interchangeable, and the purchase and repairs of components could be done in volume to economize.

Fuels would be purchased for all the cogeneration units and therefore significant volume discounts would be available.

As there are currently only approximately 22 cogeneration facilities in industry in Ontario, the technical, operating and maintenance expertise is scarce and and widely distributed. ICS Ltd. would have the distinct benefit of being able to assemble and use the specialized knowledge on a continuous basis as it markets and maintains these cogeneration facilities. With its expertise and the ability to standardize the power plants, standards of efficiency and performance can be set for each unit that would represent its optimum level of performance. These standards are not usually applied to power plants now, therefore most of them operate at sub-optimum levels in their use of fuels.

B. Marketing Potential and Strategy

Cogeneration is financially feasible for most companies that continuously use at least 100,000 pounds per hour of steam in their process and have an average electrical demand of 5,000 kilowatts or more, with a load factor of 70%. The financial feasibility improves with the increase in steam requirement and load factor, as on the average, 5,000 kilo-watts of power can be generated for every 100,000 pounds per hour of steam. In Ontario alone, as indicated earlier there are 98 units with the necessary steam conditions. Of these, 43 are thought to be likely customers for ICS Ltd.'s services over the period 1980-1990.

The user or customer for the utility services, although an equal partner with ICS Ltd. in the cogeneration facility, would incur no out-of-pocket costs to develop the facility. The user's only contribution would be the existing power plant at its appraised fair market value and this would be treated as his equity in the venture. ICS Ltd. would retain an equal equity position and negotiate the financing of the capital project. Subsequently, the user would only be a customer for the captive utility's output, but the utility would be administered by ICS Ltd.

The captive utility would supply all the customer's steam requirements and some portion or all of his electricity requirements. The customer would be billed at his current costs of approximately \$3.50 to \$5 per 1,000 lbs. of steam and \$.016 to \$.022 per kilowatt hour depending on the size of load and the load factor (similar to Hydro rates) so that his utility costs would not be increased. However, periodically on the basis of anticipated improved power plant efficiency, economies of scale and purchasing economies, any surplus, after all direct and allocated costs are covered, would be rebated to the customer in the form of dividend. This rebate represents the financial incentive for participating in the joint venture for the customer. Therefore under this arrangement, the customer's utility costs would not increase but could decrease. There would still be incentive for the company to practice energy conservation and load management, because the customer would still be charged the market price for the utility services, and billed for electricity using the Ontario Hydro price structure. This arrangement, therefore, minimizes the company's capital commitment and yet offers an opportunity for reducing utility costs, making it effectively risk free, and an attractive overall package.

The Capital Requirements are Significant

The sales forecast indicates that the target for ICS would be to have 43 co-generation sites by 1989-1990.

This represents a capacity of 14.6 million pounds per hour of steam and a generating capacity of 720 mw. To achieve this sales forecast, a capital expansion program representing expenditures of approximately \$400 million over a period of ten years would be necessary. The total sales of steam and electricity by ICS Ltd. is estimated to be approximately \$520 million on the tenth year of operation.

This expansion during the first five years would be financed primarily through borrowings. Internal financing of ICS Ltd. is not feasiable, as retained earnings are insufficient to meet the company's capital requirements. This analysis indicates that approximately \$30 million of initial financing or seed capital is required in 1980, and this amount increases to \$140 million by 1985. Subsequently, the company can generate enough earnings to make additional outside financing unnecessary.

The costs used in our analysis represent the best estimates based on available information from existing cogeneration facilities. However in estimating costs, an attempt has been made to be conservative, so that these costs are most likely over-stated. The analysis does indicate the relative degree, and the timing, of profitability of ICS Ltd. in meeting its sales objectives.

III Conclusion

In this paper I attempted to outline in very general and conceptual terms a means of promoting cogeneration in industry utilizing the private sector without government assistance. The vehicle for this promotion is a hybrid private utility which, through joint venture arrangements with individual companies, would effectively supply turn-key cogeneration operations. This company would then operate and maintain the power plants. Based on a number of assumptions and the application of available and estimated costs, a financial analysis indicates that this venture could break-even in 1984-85 and in subsequent years could be reasonably profitable, with profit on sales after taxes of about 13% and return on investment of about 17 per cent.

Discussion:

Industrial Development and Joint Venture Approach to Industrial Cogeneration

ALEX JUCHYMENKO,

Superintendent, Load Management Dept., Ontario Hydro

Question: Ian Rowe, *Ministry of Energy*

I just wanted Alex's public assurance that the proposal here, which of course is a proposal, is predominantly a management venture operation, and is not in direct competition with the existing private sector consulting community, but indeed such a venture would actually generate new business and markets for our existing private sector indutrial consultants.

Question: Mr. C. Planzer, *Dominion Textile*

One question, or clarification. This ICS power would only be used by the plant where it is generated, is this right?

Answer: Mr. Juchymenko

Our estimate indicates that out of 720 or so megawatts, only about 150 MW would be more than what the customers (or these 43 plants) would utilize in the ten years that we have projected, so that 150

MW would be sold to Ontario Hydro. I think there will be a paper later relating the conditions under which the power could be sold to Ontario Hydro. Yes, 600 MW of the potential cogeneration power would be used by the plants where it is generated.

Question: Mr. Lewarne, *Morris Wayman Ltd.*

Did you say that the private company, the private partner would put up its own generating facilities as it's part in the equity?

Answer: Mr. Juchymenko

Yes, we propose that the industry put up its own steam generating facilities as it's part in the equity. We look to see what happens to a customer that has some low pressure steam facilities right now. That particular facility would have to be utilized somehow, and we thought that that particular facility would be part of this utility joint venture. ICF would then add cogeneration facilities to it, upgrade the steam conditions, and do whatever has to be done. The company would just put up this existing unit.

Question: Mr. Lewarne

But principally the problem is that those companies only have low pressure steam. If they are using 150 psi steam, that is the boiler that they have, and it doesn't seem to be very profitable to try and co-generate electricity form 150 psi steam.

Answer: Mr. Juchymenko

Well I agree that if you have a facility with low pressure steam boilers, then you would have to wait until you are either expanding, or changing, or you may have to wait until those facilities must be replaced. We are talking 10 years ahead, and our forecast indicates that for the first three years there will be very little done in this field. There are some new plants that are in the planning stages right now, and, of course, that would be incorporated right away. There are some new companies which are opening for business, and co-generation would be probably one of the alternatives that they could look at.

Question: G. Weldon, *Union Carbide*

In this ICS concept is there provision for more than one plant? I'm thinking in terms of two or three smaller plants that aren't within these 100,000 lb and/or 5 MW limits that you have established, but is there provision for two or three plants to combine in one of these ICS units? Possibly one plant has waste materials to incinerate, another plant has a low pressure steam requirement and the third plant needs the electricity.

Answer: Mr. Juchymenko

Yes. This concept is very flexible and can combine two or three plants from the same firm under one ICS unit. First of all they would probably like to utilize the wastes as much as they could because there is some government assitance in this field. 100,000 pounds is a good round number, although I know some people who have, at the present time, a much lower rate of steam flow where they generate electricity now, so I guess that's a possibility. Besides this would be a contractual agreement so it would have to be suitable for both the customer and ICS Limited.

Question: Dave Strathern, *Spruce Falls Power & Paper Company Limited*

As I understand it, the existing facility would be turned over to ICS in order to establish an equity position. Would there be difficulties with the contractural agreements that a company might have with its union force, in that the people that are manning the facility, would they be turned over also and all the contractural obligations that had been given to them, would they be honoured?

Answer: Mr. Juchymenko

Well, first of all, we have looked at the union problem because there are other reasons besides the one you have indicated. What happens if there is a strike within the plant; you pretty well have to close the other production facilities. So this would have to be worked out as part of the overall company procedure on which property this generating facility exists. So the labour force and their existing agreements would have to be honored until they are re-negotiated, or the contracts must be negotiated as one package.

Question: Sam Archer, *Ford Motor Company (Canada)*

What about a company that already has cogeneration facilities? Could they be taken over in some way on this plan, if it met the criteria?

Answer: Mr. Juchymenko

Yes, the proposal of this company ICS Ltd. is exactly for that type of operation. We are looking at the cogeneration aspect, that means both steam and electricity would be supplied. Of course there is the possibility that this company could just generate steam and sell steam to the company. It would still be beneficial, I think to some companies, that this company would just produce steam and sell it to the company and in the US there are several operations like that. But yes, the existing cogeneration facilities can be taken over by ICS Ltd. if both parties agree to it.

Question: Sam Archer *Ford Motor Co. of Canada)*

One other question, I missed the rate you were talking about for steam.

Answer: Mr. Juchymenko

$3.50 for 1,000 lbs at about 250 psi, 400 degrees.

Question: Al Thom, *E. B. Eddy Forest Products Ltd.*

If we have a cogenerating plant and it goes down, are they going to look after the penalties if we get hit by Hydro?

Answer: Mr. Juchymenko

It would be a contractual agreement between the ICS Ltd. and the industrial plant. ICS would make the necessary arrangements with Ontario Hydro in cases of cogeneration outage or emergencies. Their only business would be co-generation and therefore they would undertake more studies and research,

and they would probably negotiate with Ontario Hydro more often than most companies.

Question: A. Thom, *E. B. Eddy Forest Products Ltd.*
The other question is; would they be interested in the water conditions too? There has been nothing said about cogeneration with water power.

Answer: Mr. Juchymenko
That particular problem we kind of steered away from because we thought there were not that many hydraulic generating facilities available, but this would be a private industry I'm talking about, and if there is a potential, or if a profit could be made, I think they would consider it. After all they would have the expertise to do that type of operation.

Question: Gordon Robb, *Dept. of Energy, Mines & Resources (Ottawa)*
I would just like to comment that there is some experience with the joint venture utilities in Canada. There is one joint venture utility, the one which serves the Syncrude plant. This is a joint venture by the Alberta Energy Company, and the Calgary Power Company. A lot of the capital structure is debt and preferred equity, and there are revenue guarantees so there isn't very much risk there, but one of the interesting things that has happened is that the Alberta Public Utilities Board has been charged with the responsibility of determining the return on common equity that AEC Power can use. I would like to commend Alex Juchymenko on this idea. We have some experience in working with the utilities in New Brunswick and Nova Scotia who directly own cogeneration facilities, and when the utility itself does own these facilities, I think that is defintely a realistic option. However there is some talk about that utility giving a special deal to one customer. Whereas if you have a separate cogeneration joint venture, a separate entity such as ICS, you get away from that problem and there are a lot more financing possibilities.

Question: Dr. J. Uvira, *Steel Co. of Canada Ltd.*
Who is going to provide the standby power to the plants where this cogeneration installation will be? Is it going to be through the ICS or through Hydro?

Answer: Mr. Juchymenko
Well of course you are looking at an organization that is not in existence right now. But we are also looking at a very large organization, 750 MW or it could be higher; maybe a 1000 MW. That is a company of quite a large size, and therefore they would work with Ontario Hydro to have the best combination of the standby power and the reliability of the cogeneration facilities, and many other things. Right now, of course, the reliability and the standby power is supplied by Ontario Hydro. It still could be the same arrangement, because it might be economical to have that particular standby power bought from Ontario Hydro. We have not looked at that alternative.

Written Comments

Question: G. Bradwell, *Supervisor Area Transmission Planning British Columbia Hydro and Power Authority*
I have set down a few thoughts for your consideration.

My comments are based on notes made at the time of the meeting and reflect my understanding of what was said. I would like to refer specifically to three papers:

1. Cogeneration Potential and Joint Venture Approach, A. Juchymenko;
2. Economic Impact of Industrial Cogeneration on Electric System Expansion in Ontario, Dr. D. A. Drinkwalter; and
3. By-Product Fuels for Use in Cogeneration Systems, R. D. Winship.

The idea of establishing, ICS, a separate corporation to own, operate and maintain cogeneration plant is an interesting one but fraught with difficulty. One of the chief disadvantages is the problem of ensuring that the industrial plant will be supplied with its required process heat. At present nearly all industrial plants own, operate, maintain and control their process heat supply. The acceptance of loss of this control may be difficult to sell to industrial plants.

ICS would have to operate as a utility delivering process heat to a local user and electricity to the local user and an electrical network. In the presentation there was the suggestion that the minimum size of installation that would be considered economic was 5 MW. This is somewhat at variance with the 15 MW break-even suggested by Dr. Drinkwalter but perhaps it can be explained by a difference in assumptions made. For example, did Dr. Drinkwalter assume cogeneration plant financing to be by the industrial organization? -and did Mr. Juchymenko assume 100% equity financing (at a reduced fixed charge rate) for ICS? Mr. Winship expressed the thought that cogeneration might be possible down to 10 MW - again the conditions he assumed were not clear.

Answer: Mr. Juchymenko

Each of the three speakers based their figures on different criteria. Mr. Winship's assumptions were made from a technical point of view, although doubtlessly economics were taken into consideration. Dr. Drinkwalter used U.S. figures, which vary slightly from Ontario figures. His assumptions were:

(1) 40% corporate tax rate

(2) 25% capital cost allowance

(3) 15% after tax cut-off rate (profit)

As for my paper, I used Ontario figures as reported by Mr. D. Dick in his recent survey, and my assumptions were:

(1) 50% coporate tax rate

(2) 50% capital cost allowance

(3) 15% after tax cut-off rate (profit)

I assumed two thirds debt financing and the remainder to be equity financing, of which 80% could be preferred shares.

Comment: J. G. Cassan, *Manager Divisional Projects, Ontario Hydro*

1. In cogeneration feasiblity studies care must be exercised to avoid overly-optimistic assumptions. In conversations at the conference - and in some of the discussions - I heard mention of sub-optimal operation of cogenerators,
   (a) because of variations in plant demands for steam and electricity and
   (b) because of failure of operating staff to implement design modes of operation.
2. Cogeneration system reliability is a critical factor in performance and profitability which was mentioned only in qualitative terms. Perhaps as part of its contribution to cogeneration development Ontario Hydro could apply recently developed techniques for estimating reliability levels of power systems.
3. A limited technical consulting service might be offered by Ontario Hydro to assist smaller companies with limited technical resources in evaluating cogeneration proposals. This would have to be done in such a way as to avoid competition with private consulting firms.

Relationship of Industrial Generation and Ontario Hydro's Expansion Program

DR. D. A. DRINKWALTER
Chief Economist,
Ontario Hydro

This paper examines the economics of industrial cogeneration and its potential implications on a number of alternative system expansion scenarios. The analysis involves estimating the potential industrial generation capacity in Ontario together with the capital and operating costs of these installations. The internal rate of return of each installation type is calculated based on the cost savings of cogeneration over the alternative of purchasing power from Hydro.

Introduction

This paper examines the economics of and the potential for industrial generating capacity in Ontario. Of particular interest is the potential impact of reduced reliability of the Ontario Hydro system with low generating reserve margins. The analysis involves estimating:

(1) the potential industrial generating capacity in Ontario;
(2) The internal rate of return of each installation type, based on the cost savings of own generation, over the alternative of purchasing power from Hydro; and
(3) Then recalculating these internal rates of return with the costs of power supply interruptions included in the cost savings.

The resulting estimates are then used to evaluate the amount of investment in own generation which might be induced.

Two groups of industrial power generation installations are distinguished here. The first consists of cogeneration plants. In this situation a firm which requires steam for process purposes is able to pass high quality steam through a turbine, which reduces the temperature and pressure to process conditions. The second group is composed of firms which have no process steam requirement and where one would expect to find utility-type condensing turbines. This distinction is made because for cogeneration the cost of power equals the incremental cost of generating electricity in addition to steam, and is therefore much lower than it is for non-cogeneration where all operating costs are attributable to electric power. Similarly, a sub-group of cogeneration plants was formed made up of installations where investment in new steam plants would be required before power generation would be feasible. For these plants the capital cost of the new steam plant would be included in the cost of electricity generation.

Table 1 contains estimates of the installed capital costs of industrial generating facilities as reported in a 1975 Dow Chemical study and a 1976 report by the Thermo Electron Corporation.

TABLE 1

ESTIMATED CAPITAL COSTS OF INDUSTRIAL COAL-FIRED GENERATING INSTALLATIONS OPERATIONAL IN 1980

	IEC		Thermo Electron	
Capacity (MW)	$ per kW	Total Cost ($Million)	$ per kW	Total Cost ($Million)
5	1,040	5.20	1,470	7.35
15	830	12.45	1,100	16.50
25	750	18.75	930	23,25
50	650	32.50	820	41.00
100	570	57.00	750	75.00

Note: Based on exhaust steam at 80 psig and 1,250 psig boiler pressure.

These estimates indicate the existence of considerable economies of scale. While the cost per kilowatt declines as the size of the facility increases, the costs decrease more slowly beyond the 15 MW range.

Because of the difference between these two sets of estimates and the lack of information pointing to one or other set being more reasonable, it was decided to use an average in determining power costs for coal-fired plants. For oil-fired plants the Thermo Electron

study provided the only source of costs estimates. For these installations a set of estimates was derived by assuming that the relation between the average and the estimates derived is the same for both coal and oil-fired plants. The resulting figures after escalation to reflect the cost of installations operational in 1985 are shown in Table 2, which indicates clearly that oil-fired stations require a lower investment.

TABLE 2

ESTIMATED CAPITAL COSTS FOR NON-COGENERATION INDUSTRIAL GENERATING INSTALLATIONS OPERATIONAL IN 1985

	Coal-fired		Oil-fired	
Capacity (MW)	$ per kW	Total Cost ($Million)	$ per kW	Total Cost ($Million)
5	1,850	9.25	1,310	6.55
15	1,430	21.45	960	14.40
25	1,240	31.00	8.70	21.75
50	1,090	54.50	750	37.50
100	970	97.00	700	70.00

Note: The costs shown here are in 1983 dollars based on the simplifying assumption that all instruction occurs in 1983 for plants operational in 1985.

Annual Costs

Clearly, capital costs are only part of the total costs which must be considered. Three categories of annual costs are identified.

(1) depreciation;
(2) operating and maintenance expenses; and
(3) fuel costs.

For simplicity, depreciation was calculated on a straightline basis for a 30-year plant life. Estimates of the total operating and maintenance costs were derived from the Dow Chemical and SNC Consultants reports. These yielded values of $40/kW for the 5, 15 and 25 MW plants and $35/kW for the 50 and 100 MW plants. For cogeneration, the incremental O&M costs are $20/kW and $16/kW. respectively (1, 3). Fueling costs were calculated on the basis of the 1973 cost of coal and fuel oil to Ontario manufacturing firms escalated to the required period. The resultant values for 1985 were $2.6 per million BTU for coal and $4 per million BTU for fuel oil. These values equate to $67.10 per ton of 26 million BTU per ton of coal and $.72 per gallon of fuel oil. An amount of two percent of the capital cost is included to cover property taxes and other miscellaneous capital-related costs (1.)

Provision for backup power to cover maintenance and unplanned equipment outages has to be made. This analysis included the purchase of the backup from Ontario Hydro, since this was cheaper than the alternatives: principally, the need for the firm to install and maintain its own reserves.

Potential Inplant Generating Capacity

The potential industrial generating capacity is estimated at approximately 3,000 MW divided almost equally between cogeneration and non-cogeneration facilities. Table 3 indicates the distribution of this potential between cogeneration, cogeneration requiring new steam plants, and non by-product facilities. These potential installations are heavily skewed in favour of small plant sizes, although the major capacity potentials result from the large plants.

These estimates drew heavily on the results of a survey of industrial steam plants in Ontario by Leighton and Kidd Ltd. (4). Included are some non-industrial installations, such as universities, hospitals and commercial firms, which operate steam plants to provide heating during the winter months.

TABLE 3

POTENTIAL INPLANT GENERATION CAPACITY

	Cogeneration		Cogeneration With New Steam Plants		Other Than By-Product Power		
Size of Installation(1)	Number of Firms	Capacity	Number of Firms	Capacity	Number of Firms	Capacity	Total Capacity
Less than 10	54	270	29	145	42	250	665
10 - 19.9	12	180	11	165	16	206	551
20 - 29.9	7	175	3	75	5	123	373
30 - 69.9	4	200	3	150	11	493	843
70 and Over	1	100	1	100	3	381	581
TOTAL	78	925	47	635	77	1453	3013

(1) Based on maximum demands of the potential non-cogeneration installations.

Potential Investment in Own Generation

Using the distribution shown in Table 3 and the capital cost estimates of industrial power plants, total potential investment in self-generation was estimated.

This is shown in Table 4. The potential capacity estimates in that table refer to the position in 1977 and on that basis, maximum investment potential is estimated to be between $2.3 billion and $3.3 billion for a total capacity of about 3,000 MW. In order to estimate potential capacity for years after 1977, it was decided to assume that the growth rate of potential capacity would be half that of industrial output. Forecasts of the latter were taken from the DRI model of the Ontario economy. In this way, rough estimates of potential capacity in 1985 and 1990 were made. For 1985, maximum investment potential is between $2.8 billion and $4.0 billion for a capacity of about 3,600 MW, and for 1990 investment is between $4.3 billion and $6.0 billion for a capacity of 4,000 MW.

The amount of this potential investment which would actually be undertaken would depend on the relative costs of power from own generation and purchased from Hydro. The average cost of electricity to bulk power customers for eight different expansion programs was calculated. However, such a comparison is inappropriate because it ignores the fact that a firm considering an investment in self-generation would require a competitive return on its investment. An assumption of a 40 percent corporate tax rate, together with a capital cost allowance of 25 percent and an after tax cut-off rate of return of 15 percent, was adopted in this study.

The internal rates of return for the various types of inplant generation installations were estimated for plants operational in 1985 and 1990. In the light of the assumption of 15 percent as the minimum acceptable return, only cogeneration can generally be considered as an economically viable alternative to purchasing power from Hydro. For such plants operational in 1985, all but the smallest have returns exceeding 15 percent, while the effect of postponing the investment until 1990 is to slightly reduce all returns and raise the minimum economic plant size to 25 MW.

TABLE 5

INTERNAL RATES OF RETURN FOR INDUSTRIAL GENERATION INSTALLATIONS OPERATIONAL IN 1985

Plant Type	Cogeneration (%)	Cogeneration With New Steam Plants (%)	Non-Cogeneration Facilities (%)
5 MW coal	11.9	7.3	1.0
oil	10.9	7.2	
15 MW coal	15.3	9.1	1.3
oil	14.5	9.3	
25 MW coal	17.5	10.2	1.5
oil	16.8	10.2	
50 MW coal	19.8	11.6	2.2
oil	19.7	11.9	
100 MW coal	22.7	12.8	2.5
oil	21.5	12.6	

Note: These are based on a continuation of Ontario Hydro's basic expansion program, containing a 2:1 nuclear - coal mix and a target reserve level of 25 percent.

TABLE 4

POTENTIAL INVESTMENT IN SELF-GENERATION BY INDUSTRY

	BY-PRODUCT POWER				OTHER GENERATION			
			Potential Investment ($ Million)				Potential Investment ($ Million)	
Size of Installation MW	Number of Firms	Potential Capacity (MW)	Coal-Fired	Oil-Fired	Number of Firms	Potential Capacity (MW)	Coal-Fired	Oil-Fired
5	54 (29)	270 (145)	278 (268)	216 (190)	42	210	388	275
15	12 (11)	80 (165)	137 (236)	101 (158)	16	240	343	230
25	7 (3)	175 (75)	112 (93)	82 (65)	5	125	155	109
50	4 (3)	200 (150)	112 (164)	80 (113)	11	550	600	413
100	1 (1)	100 (100)	47 (97)	35 (70)	3	300	291	210
Total	**78 (47)**	**925 (635)**	**686 (858)**	**514 (596)**	**77**	**1,425**	**1,777**	**1,237**

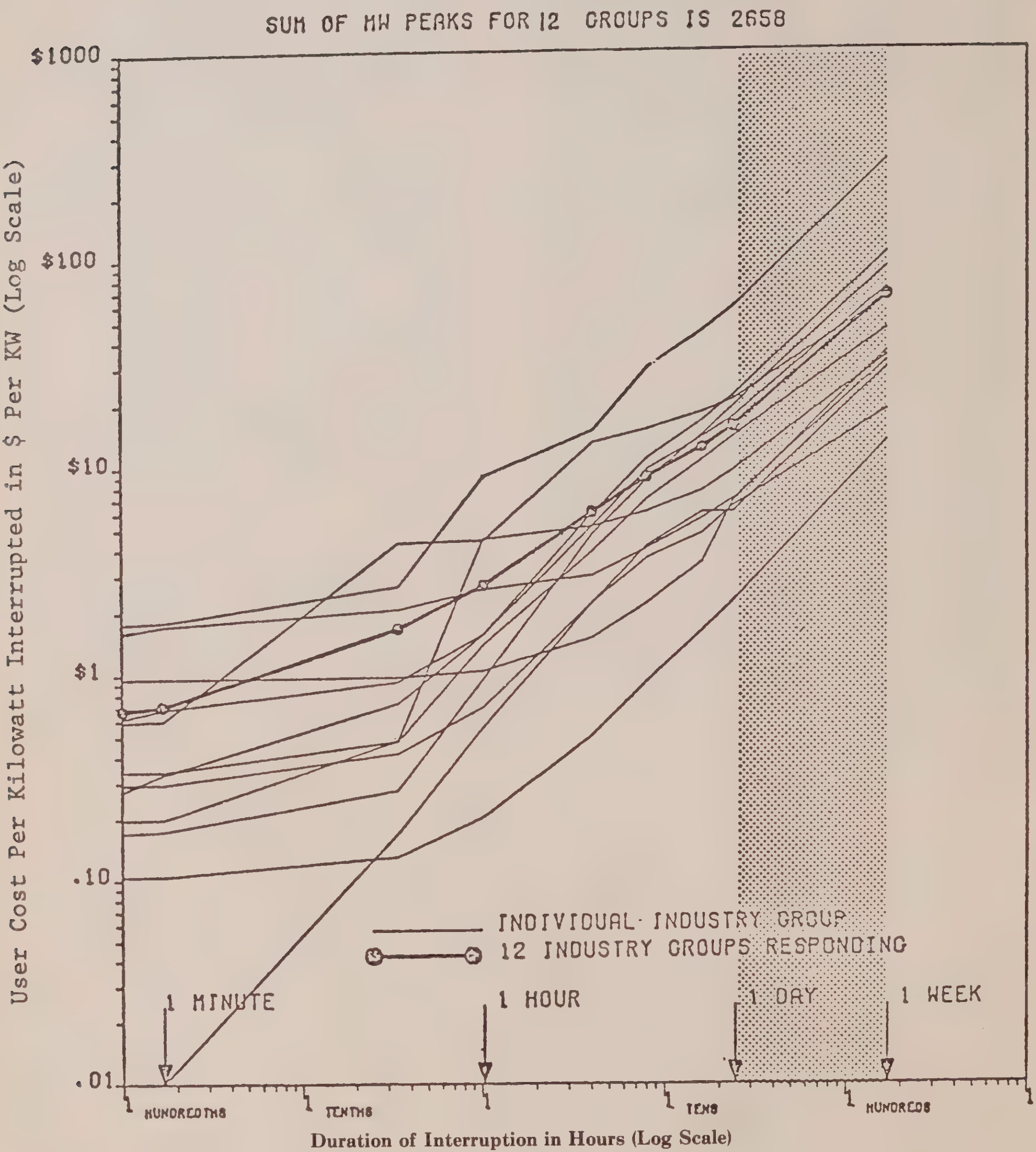
Note: The figures in parentheses refer to potential cogeneration installations where new steam plant is required.

Effect of Interruptions on Investment by Industry

The total cost to a firm of taking power from Hydro is made up of two components, the cost of delivered power and the cost of interruptions in the supply. Estimated interruption costs for large users in 1976 are shown in Figure 1 in terms of dollars per kilowatt interrupted for durations varying between less than a minute to one week. For the sake of simplicity, however, an interruption period of one hour has been used throughout this analysis. It will be noticed in Figure 1 that average interruption costs vary widely

FIGURE A

$/KW INTERRUPTED FOR SPECIFIED DURATIONS



Note: Cost are for 1976.

Source: Ontario Hydro Survey on Power System Reliability: Viewpoint of Large Users

between industries; for a one-hour interruption the range is roughly from $.20 to $8 per kW. In this analysis the overall average cost has been used partly for simplicity and also because estimates of cogeneration potential could be made only on an aggregate basis. The estimated average cost for a one-hour interruption is $4.70 per kilowatt in 1985 and, because an interruption period of one hour has been used, this is also the average cost per kilowatt-hour of undelivered energy. The rate of return earned by own generation installations when interruptions are considered includes estimates of the amount of unsupplied energy for individual users for each year in the period 1985 to 1997. These system losses were allocated between customers according to their relative importance within the system.

The unsupplied energy costs are additions to the own generation cash flows and, after they have been adjusted for tax, revised internal rates of return were estimated. These are shown in Table 6. When interruption costs are excluded, the rates of return of each plant type shows a steady increase with reserve margin reflecting the higher cost of power under a high reserve scenario. The effect of including interruption costs is to increase considerably the returns for the lowest reserve conditions, but have little or no effect on those for 25 percent and higher system generation reserve margins. As a result, the minimum internal rate of return on cogeneration occurs at the 25 percent reserve margin.

In order to estimate how much of the potential investment in own generation could be realized, the rates of return are compared to the assumed cut-off rate of 15 percent. Several conclusions emerge from this comparison.

First, of the three types of industrial generation considered, only cogeneration is, in general, economically viable. Secondly, while the inclusion of interruption costs in the analysis increases the internal rates of return it has only a marginal effect on the amount of total potential investment in own generation which can be considered realizeable. On this basis, therefore, existing potential cogeneration investment would be between $300 million and $400 million (in 1983 dollars) assuming installations operational in 1985, with a capacity of about 650 MW. Using the assumption that potential capacity would increase at half the rate of industrial output, this potential investment would have increased to between $370 million and $500 million with a potential capacity of about 800 MW in 1985.

TABLE 7

MAXIMUM POTENTIAL INVESTMENT IN OWN GENERATION IN 1985

Reserve Margin (%)	Maximum Potential Capacity (MW)	Maximum Potential Investment ($Million)
15	1,125	619 - 827
25	810	367 - 503
35	810	367 - 503

In conclusion, it would appear that the potential impact of reduced reliability of power supply from Ontario Hydro would be relatively small. With 25 percent reserve margin or greater, where the system losses are zero, cogeneration plants of 15 MW or more would be viable in 1985. The effect of going to a 15 percent reserve is only to make smaller cogeneration plants economic. The after tax rate of return which could be earned on non-cogeneration installations and on cogeneration plants where investment in new steam plants is also required is below 15 percent, even including interruptions costs.

TABLE 6

INTERNAL RATES OF RETURN FOR INDUSTRIAL GENERATION INSTALLATIONS OPERATING IN 1985 — INCLUDING INTERRUPTION COSTS

Plant Type	Cogeneration			Cogeneration With New Steam Plants			Non-Cogeneration Facilities		
	System Reserve Margins			System Reserve Margins			System Reserve Margins		
	15%	25%	35%	15%	25%	35%	15%	25%	35%
5 MW Coal	13.9	12.1	12.6	8.1	7.4	7.7	2.2	1.1	1.5
Oil	13.6	11.2	11.7	8.2	7.3	7.7			
15 MW Coal	16.5	15.4	15.9	9.4	9.1	9.5	2.0	1.4	1.9
Oil	16.2	14.7	15.5	9.8	9.4	9.9			
25 MW Coal	17.9	17.6	18.3	10.6	10.3	10.7	2.4	1.6	2.2
Oil	17.4	16.9	17.9	10.7	10.2	10.9			
50 MW Coal	21.1	20.0	20.7	11.7	11.6	12.2	3.1	2.3	3.0
Oil	21.5	19.9	20.8	12.0	12.1	12.7			
100 MW Coal	23.6	22.8	23.6	13.2	12.9	13.4	4.0	2.7	3.4
Oil	22.9	21.7	22.8	13.2	12.7	13.4			

Note: Based on an Ontario Hydro system expansion program of 2:1 nuclear - coal generating mix.

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Discussion:

The Economic Impact of Industrial Co-Generation On Electrical System Expansion in Ontario

DR. D. A. DRINKWALTER

Chief Economist, Ontario Hydro

Question: Bill Newby, *Canadian Boiler Society*

I would be greatful for some details of the terms of reference for your 100 MW cogeneration unit. The only plant that I can think of that has that sort of steam producing capability is Polysar. I think there is some 80,000 odd horses, a large part of which is in the form of compressor drives.

Answer: Dr. Drinkwalter

We relied heavily on the Leighton & Kidd study. What they found confirms your suspicions. Obviously the potential is concentrated with small units rather than large. For example, in the pure cogeneration activity of 5 MW or smaller stations, they were looking at 54 firms in that category. At the 100 MW level they indentified 1 firm in the pure cogeneration position, and they only identified 3 at the 100 MW level that would be in the pure generation of electricity business, the small utility. Distribution very heavily weighted to the small station.

Question: Gordon McGorman, *Algoma Steel*

I take it that none of us here know whether we have been selected as potential brides or not, but our numbers must be few from what you say. For the rest of us, it would appear from what has been said that nobody is likely to be able to generate more power than they themselves use, and really the options open to us is to use more by-product fuel and recover more waste heat than we presently do and use that either to shave peak or to buy fewer kilowatt-hours. Now a few years ago the incentive, the reduction in kilowatt-hour rates as a function of load factor was removed. In each of our own companies whatever you can think of to do everybody's cash flow will be different, but the payoff is by how much we will reduce our electricity bill. I am wondering if in your economic studies there was any indication of a change in balance between the demand rate and the energy rate, or any possibility of a return of an incentive for high load factor?

Answer: Dr. Drinkwalter

The simple short answer is no. We did not in this study get involved with assessing the implications and impact of things such as time of day rates or anything of that nature, or changes in the demand energy split, other than to take the forecasts which were available internally for the total cost of power, and project those out, I believe using the same demand energy split. That is another very good caveat in what we might expect downstream in

terms of differences. I depends on the kinds of rate restructures as opposed to, or in addition to the level of rates that we are talking about in the future and any changes that come about in the demand energy split and we will have to await the report of the study of the Ontario Energy Board on that. They are looking at a number of options at the moment. Do you have any comments you would like to make on that Alex?

Mr. A. Juchymenko

We have not looked at rates. I think that the problem in Ontario is that the Ontario Energy Board has been looking at this idea of rates for the last couple of years, and really I am not in the position to make a statement of what will be the best combination of rates for industry.

Dr. Drinkwalter

Our studies here simply looked at the total bill and the total level, assuming the same kind of rate structure.

Question: Gerry Lewarne, *Morris Wayman Limited*

I am a little concerned, Dr. Drinkwalter, about the 15% return after tax. Can you tell me what percentage of the cost of operating the cogeneration facility is taken up by capital charges?

Answer: Dr. Drinkwalter

I can't off the top of my head, I don't have it here.

Question: Mr. Lewarne

But you see the point that if I would own a private company and I have to borrow at 13% and I have to fulfill the 15% after tax return, that I have much more of a problem generating electricity and steam than you do as Ontario Hydro when you can borrow it at 10-1/4% or 10-1/2% and only need to break even.

Answer: Dr. Drinkwalter

Well, of course we do. That's one of the reasons we (Ontario Hydro) exist and have the low cost we do in this province.

Question: Mr. Lewarne

O.K. Why don't you pay for the boiler, then. Did you calculate that in, so that we don't have to pay the high interest charges?

Answer: Dr. Drinkwalter

So that Ontario Hydro is building facilities in around the province? No we did not. I don't know whether there is a good reason why we didn't, but one of the reasons obviously has to be that we are spending enough of our own money on our own facilities.

Answer: Mr. Juchymenko

In our particular study we have looked at various costs, breaking down costs like the energy costs, the fuel costs, the capital costs, etc. The capital costs depend on the size of the unit. It varies between 15% and 20% of the cost of delivering power and steam. So it is not that high, because the fuel costs are very expensive. They vary from 60-70% of the total energy delivered to the customer.

Question: Mr. Donaldson, *Texas Gulf Canada Limited*

I am interested in the way in which you included escalation in your energy operating costs and also included heavy inflation charges in your minimum rate of acceptable return.

Answer: Dr. Drinkwalter

Everything was escalated. We undertook the study on the basis of the costs as they were today, capital costs, and escalated those components through to an in-service date of 1985. We escalated the cost of fuel, and we took the escalation values of the operation and maintenance costs. They were all put in terms of current dollars at the operating points coming in service in 1985 and operating beyond that, obviously. That is consistent with the way that we do our costing approaches within Ontario Hydro and also consistent with the cost of power forecast that we were using as the alternative.

Question: Mr. Donaldson

Was your decision point 1978 or was it 1985?

Answer: Dr. Drinkwalter

The decision point was 1978 for a plant in service in 1985.

Question: Donald Dick, *Dick Consulting Services*

Dr. Drinkwalter, would you agree that one of the limitations to forecasting the potential for cogeneration would be that your study has bypassed the problem of salvaged fuels, particularly in the pulp and paper industry, but some of the other industries too, and therefore there is a replacement cost on those boilers using that fuel which are very complex and very costly. How would it affect their replacement cost, since the actual economics of cogeneration are dictated to some extent by those capital costs?

Answer: Dr. Drinkwalter

I really don't know about the capital costs. Certainly in terms of the fuel. What we attempted to do was on a pure cogeneration side where the additional steam plant was required. We calculated only the incremental costs of additional fuel or additional capital expenses involved in generating electricity. Whether or not we have overlooked a significant capital cost component in that, we may well have. And that is why I think that it is important, and why I tried to put the caveat early, that it is important to look at each individual company and industry as an entity, and it is very difficult to generalize.

Question: Mr. Dick

I don't think you will make a case from completely pure fuel, the thing is that you are going to burn the salvaged fuel anyhow. Any fossil fuels that you burn for making electricity is extra cost on top, and not always justified at the present time.

Answer: Dr. Drinkwalter

That is certainly true.

Question: George Weldon, *Union Carbide*

Do your capital costs include the capital cost of pollution control at the level you anticipate for 1985?

Answer: Dr. Drinkwalter

I really can't answer that without going back to the consultants' study. I am inclined to think they do not, looking at the numbers.

Industry's Stake In Energy Planning

W. O. TWAITS
The Business Council on National Issues.

Industry's Stake in Energy Planning

I welcome this opportunity to participate in such a timely conference. It is interesting to note that energy has received little attention, except as a resource development, until the price sharply increased. Indeed, we have produced generations of citizens with not even a rudimentary knowledge of the element on which their very existence depends — namely energy.

The frustration of trying to explain the energy situation to a lay audience is quite unbelievable. Thus, I am doubly happy to be in a milieu which can relate a BTU to a Kilowatt.

You are today discussing in a series of papers, the specific subject of "Cogeneration of Steam and Power." A few years ago, this was a matter only for special situations such as remote locations. Now the rising cost of energy presents a new stimulant for this and conservation efforts of a wide variety which have produced some dramatic reductions in per unit/energy consumption at very little capital expenditure. I remember that when oil prices increased, many companies did not even know the cost of energy in their operations, because it was insignificant. Now, they are chasing low-level heat recovery defined as "anything exceeding body temperature."

Cogeneration is energy conservation in two ways — by heat recovery and by reducing transmission losses. As a capital project, it must be conceived in the light of three trends:

First, the certainty that the real cost of energy will continue to increase. As in the case of non-ferrous minerals, steel, and, indeed, all the basic industries, this is not just inflation, but a reflection of growing capital intensivity, costly environmental standards, more remote sources of raw material and tax policies by various levels of government.

Secondly, increasingly stringent environmental standards for air and water, some of which are beyond technological capability, increase not only capital costs, but energy requirements. Indeed, the great contradiction today is that environmental standards undermine conservation efforts.

Finally, increasing technical complexity of the whole system of producing goods and services requires large increases in the amount of energy. Computers and communication systems, for example, are large power users. Thus, it is not sufficient for industry to occupy itself only with conservation programs. It must take an active position in energy planning and development, far beyond cooperating in demand surveys.

In this context, the scenario for this conference must be recognition that Ontario is an energy-deficient province — that it is a "net buyer". To the extent it imports energy, Ontario must compromise or cooperate with national policies, both of Canada and, in the case of coal, those of the U.S. (Note recent First Ministers' Conference.) The controllable energy supply in Ontario is primarily electric power and Ontario Hydro's planning is critical to economic development in this province both as to timing and cost. Since we are fast running out of usable hydro sources, and the use of limited oil and gas reserves under boilers is indefensible by any standards, the choice for future power in Ontario lies between coal and nuclear. This is a matter of examination by two groups — a royal commission and a select committee of the legislature with the help, of course, of environmentalists.

Planning by Ontario Hydro for future power supply must be done in the framework of the energy outlook for supply, demand and cost, which is influenced not only by general economic development but by the actions of governments both in Canada and abroad. The

number of variables in this equation is staggering. Thus when I see 10-20-year projections of energy demand and supply for oil, gas, coal and power, I am reminded that given the same basic data, five geologists will produce more than five different interpretations. One thing we know is that energy demand will grow — at least with population increase. Whether it is 2.5% or 3% per annum is extremely important, but it is *not* predictable.

I suggest to you people in industry, that we must develop Ontario policies for energy development, particularly power, within another set of parameters. You will note that I have used the term "policies" — there is really no such thing as an energy policy. Rather there must be a blend of policies and we must constantly guard against offsetting objectives which, in the case of power, would include environmental regulation, land use, etc.

Nor can we afford short-term political opportunism or vacillation, because of the lead times involved in any major power project. Here we have one of the greatest problems in the development of indigenous energy supplies in Canada. In a development of fossil fuel resources, upwards of ten years from conception to operation is required — twenty years in the case of the huge Syncrude project in the tar sands. Time increases costs, but lack of continuity in government policies can be a much greater factor. A political tenure of four to five years maximum is totally incompatible with the need for orderly and efficient development of power projects, which I understand in Ontario require a minimum lead time of twelve years.

I could expand this aspect by many examples but that should be unnecessary for this audience, many of whom, I am sure, have been exposed to heavy cost overruns due to delays or changes induced by regulation or legislation.

Another important parameter for consideration is cost. Earlier, I alluded to the increase in real cost of energy due to a variety of factors. By now we should have stopped deluding ourselves that the increase in energy costs is simply due to an Arab "cartel". The fact is that tar sands, the Arctic, the offshore — indeed, all the new energy frontiers to which we must look — cannot be developed at less than equivalent world prices for petroleum, escalating at least for inflation (a side tribute to Arab/U.S. dollar pricing). It is a fact that new mine safety and health regulations alone have dramatically increased the cost of coal production. It is a fact that to exploit the enormous deposits of coal in the western plains will require huge investments in new transportation systems or on-site liquefication/gasification projects.

But in this outlook, it seems clear that nuclear power should have by far the smallest increase in real cost of production, because its major element of cost is not fuel, but capital equipment, and the associated capital charges.

Finally, there is a parameter which falls within the area of political manipulation or confrontation that must be singled out from other policy aberrations. That is the consuming desire of polititicans and bureaucrats to tinker with inter-fuel price competition. In the debate on energy policies, which has ranged so hot and heavy the last five years, both here and in the U.S., I know of no one that does not accept the fact that by artificially controlling the price of natural gas below competitive fuels, we have dissipated great reserves of a premium fuel into unjustifiable end uses. This has been done under a variety of excuses, such as limiting cost of household heating, air-quality improvement, and maintaining industry competitive position. Ignored is the fact that such countries as Japan and Switzerland, 100% dependent on imported energy, and Germany, largely dependent on imports, are the three healthiest industrial economies in the Western world.

The effect of price tinkering, as typified by natural gas, has been to set back indigenous source development by the full lead time of ten or more years. Now I don't need to tell you that fuel substitution is a complicated subject, which can only be evaluated when discussing a specific user and location. In general, however, there is practical competition between the fossil fuels. In the case of electric power, there is really no alternative for certain users as there is no alternative oil for transportation.

Oil/gas can be transported more economically than other fuels. In electric, until technical frontiers are breached (cryogenic), high transmission losses place a premium on the location of generating facilities. Tinkering with fuel price relationships by control or subsidy can obviously be a major inhibition to proper energy source development. It is also a bad thing for industry consumers, because it becomes a basis for false economics, and in the end, industry will pay more than any short-term advantage which it gains (obviously my opinion on current Federal/Alberta gas outlet controversy.)

Now, by my own logic at least, some self-evident truths for Ontario energy planning emerge, viz:

1. We cannot fine-tune the planning for supply of power to long-term forecasts of demand which cannot accurately be predicted. Therefore, the emphasis must be on adequacy or margin of safety of supply for such an essential ingredient to our way of life as power.
2. Every encouragement should be given to supplemental sources of power such as cogeneration, i.e., removal of barriers such as municipal/provincial regulation/legislation.
3. Decisions must be made *now* if we are to bring on line, major power projects by the early 90's. I have emphasized that lead times for major energy projects have been constantly increasing, not just due to complexity or size but to the lengthy regulatory approval procedures. For instance, some way must be found to reduce the cost and time consumed in developing envrironmental impact statements and acceptable design features. Someone commented recently that if EPA had been in existence in the U.S. with its present authority, the NASA officials

would be still working on environmental impact statements and would yet to have gotten a moon shot off the ground. It is unfortunate that the public and the media seem largely unaware of this and other regulatory procedures by bodies who have no accountability for the ultimate economic impact of their decisions.

4. Transcending and indeed encompassing these three guidelines is the lack of compatibility between political tenure and lead times for new projects — the tendency for legislators to tinker with inter- or intra-fuel competition, aided by a public perception that holding down prices by control or subsidy is somebody else's cost (note subway signs).

With all respect to our host today, governments have shown a total inability to operate or direct a major enterprise. I will ignore the obvious example of the Post Office, whose troubles have inflicted enormous costs on this economy. However, I was struck by a comment of Premier Peter Lougheed, at the official opening of the great Syncrude project in Alberta earlier this fall. He noted that his Government's financial participation in the project had proved to be a very educational process for the Cabinet. He said it is proof to us that governments cannot possibly direct the development or operation of such projects — and this from a man backed with the enormous resources of the Heritage fund.

All this leads me to the inevitable conclusion that with power our only controllable and critical source of energy, its direction and its policies must be determined as freely as possible without government interference. If that should be through a Crown corporation, so be it. Of course, Hydro, as with any other monopoly, must be monitored for abuse through pricing or discrimination.

Finally, I said earlier that industry's involvement in energy planning today must go much farther than conservation or co-operation in demand forecasts. It has a responsibility for not seeking to shift costs to some other place in the economy for short-term gains. It has a responsibility for participating and, indeed, continuously monitoring the effects of various legislative developments on energy supply and demand. Energy is not somebody else's business, it is the business of everybody.

Which Alternative is the Most Advantageous for the Industry

SVEN ERLANDSSON
Manager, Turbine Department
ASEA Limited, Montreal

Using traditional evaluation principles, when industry compares the cost of purchased power, which is a mix of power from "old" and "new" utility power stations, with the new cogeneration station, there are sometimes difficulties in reaching a meaningful return on investment (ROI). If, instead of using the traditional evaluation principles, one compares the actual cost of new Ontario Hydro generating capacity with cogeneration, one will find the comparison is much more in favour of the cogeneration.

As a supplier of turbine generators for industrial power generation, we have, of course, an interest in promoting that alternative, but aside from the commerical interest, I am personally convinced that by-product power generation has a great deal to offer in the form of *established technique, low investment cost, low fuel consumption and environmental benefits* that no other alternative can really compete with. Our company has, since 1968, sponsored an annual industrial power symposium and the papers produced over the years have covered most aspects of application engineering, installation and operation of industrial back-pressure turbines. I do not, therefore, intend to repeat all these aspects, but without going into details, I will give a summary of the basic principle. (FIGURE 1)

The principle is simple. As an example, an industry using 100 units of heat (112 units of fuel) can produce 30 units of electric power by adding 38 units of fuel. With the energy equivalent of 3413 BTU/kWh, this means power generated at a heat rate of 4,325 BTU/kWh - or at 79% efficiency. (FIGURE 2)

The alternative is to ask the electric power utility to produce the power at a single-purpose power plant, where 84 units of fuel will have to be burned to produce 30 units of power. This means power generated at 9,560 BTU/kWh, or at an efficiency of 36%. (FIGURE 3)

The difference is that 46 extra units of fuel energy will have to be put into the single-purpose alternative, most of which escapes via the condenser cooling water to a river, lake, or to the air, via a cooling tower. There is, for the cogeneration alternative, a clear saving in fuel consumption and also environmental advantages with less emissions.

Why then did the industry not install back-pressure turbines as soon as it had a heat consuming process??

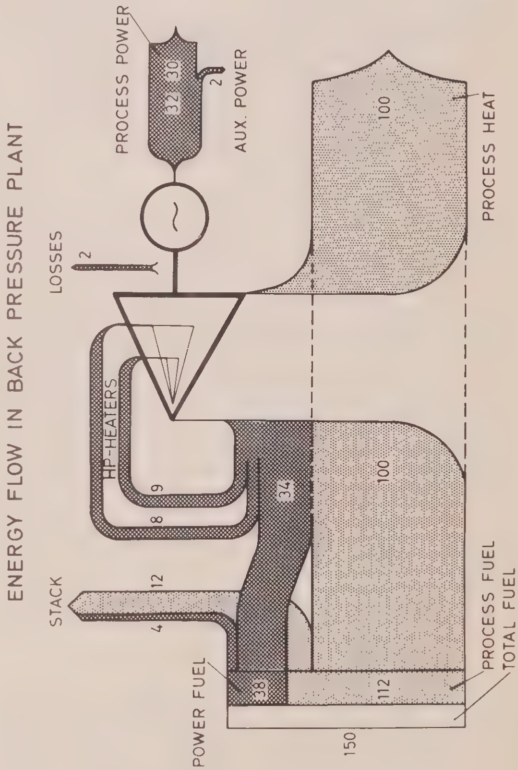


Figure 1

Traditionally, all evaluations were made through economic comparison between the two alternatives: "Purchased Power" or "In-Plant Power Generation"

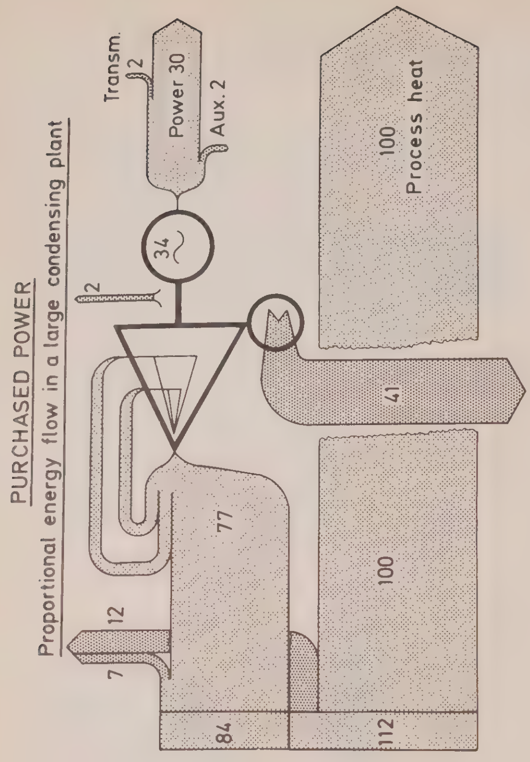


Figure 2

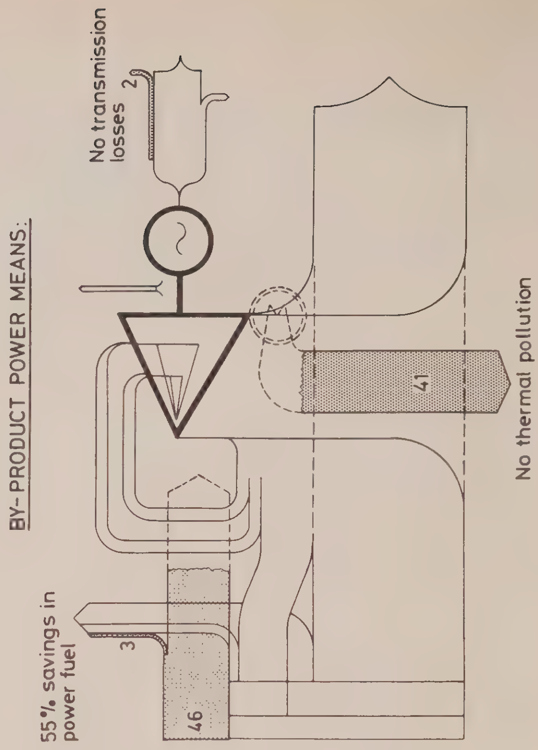


Figure 3

and such an evaluation could, back in 1974, after the so-called oil crisis, turn out as follows:

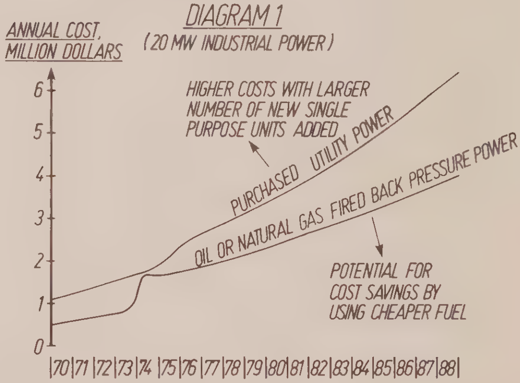
Table 1: TRADITIONAL EVALUATION (1974):
(ESTIMATED ANNUAL COST FOR 20 MW INDUSTRIAL POWER)

	PURCHASED	IN-PLANT
DEMAND CHARGE ($2.00/kW/month)	$ 480,000.00	-
ENERGY CHARGE (1.0 ¢/kWh)	$ 1,720,000.00	-
STAND-BY CHARGE ($2.00/kW/year)	-	$ 40,000.00
FUEL COST ($2.50/MM BTU)	-	$ 1,860,000.00
OPERATION & MAINTENANCE		$ 250,000.00
TOTAL COST	$ 2,200,000.00	$ 2,150,000.00
SAVING		$ 50,000.00

Now, an annual saving of $50,000.00 is not sufficient to pay the investment cost for the back-pressure turbine plant. It was obvious that with these economics, the industry could not justify the installation. (DIAGRAM 1)

Things have changed now and for 1980 it would be realistic to calculate with a cost of 2¢/kWh (demand plus energy charge) for purchased power, which would give a cost of $3,500,000.00 (instead of $2,200,000.00).

DIAGRAM 1
(20 MW INDUSTRIAL POWER)



If, at the same time, the natural gas price has increased to $3.00/MM BTU (or 1000 cu.ft.), the cost of in-plant power generation would have reached $2,500,000.00, but the gross saving has increased from $50,000.00 to $1,000,000.00

Going to 1985 and applying 3.0¢/kWh for purchased power and $4.00/MM BTU for the fuel, the gross saving will be almost $2,000,000.00.

The saving can be larger if the industry, instead of using oil or gas for fuel, uses wood waste or something similar.

When back-pressure power generation is installed, the rate of cost increase for purchased power will be

lower. To explain that statement, I will, for a moment, leave the "traditional" economic evaluation and will compare the "actual cost" for additional (new) power generating capacity, without considering who is to build the plant (utility or industry.)

TABLE 2: COST OF POWER FROM A NEW GENERATION STATION

	COAL-FIRED UTILITY PLANT (200 MW UNIT SIZE)	INDUSTRIAL BACK-PRESSURE PLANT (20 MW UNIT SIZE)
- Investment cost ($/kW)	1,000.00	300.00
- Capital Cost (15% per year, 80% load factor)	2.13 ¢/kWh	0.65 ¢/kWh
- Fuel cost ($2.50/MM BTU)	-	1.11 ¢/kWh
- Fuel cost ($1.50/MM BTU)	1.5 ¢/kWh	-
- Operation, Maintenance & Transmission	0.3 ¢/kWh	0.17 ¢/kWh
- Total cost for power	3.93 ¢/kWh	1.93 ¢/kWh

Even with a much more expensive fuel, the power from the industrial back pressure plant shows 2.0¢/kWh less cost than does the 200 MW coal-fired condensing steam power plant.

The investment cost for the industrial back-pressure plant would consist of:

— Turbine Generator with auxiliairies.
— Incremental cost for slightly higher boiler capacity and higher boiler pressure. (The base cost corresponding to a L.P. boiler must be charged to the process heat supply.) The assumption here is that the decision for in-plant power generation is made at a time when a decision is made to install a new boiler.
— Installation, Steam Piping and Electrical Connection.
— Engineering.
— Interest on investment before start-up.

This is of course valid for an *industrial back-pressure* plant (not for an industrial condensing plant).

Someone may object that I should be comparing with a large nuclear plant, rather than with a 200 MW coal-fired plant. You will find, however, if you add up Capital Cost, Uranium Fuel Cost, Heavy Water Cost, Operation Cost, Maintenance Cost, Power Transmission Cost, Spent Fuel Handling Costs, etc., that the power from a new nuclear station would be more costly than the power from the industrial back-pressure plant. (FIGURE 4)

It is obvious that "new" power stations added to the utility network will increase the cost of purchased power. If the "new" power generating capacity is added in the industry, the percentage of "new" utility power stations will be less and the average cost of utility power will be lower.

Returning to the industry and to the possibilities of receiving a return on the investment for a back-pressure turbine generator plant, I said earlier that the "traditional" evaluation may not give a sufficient ROI for the industrial plant.

One possibility would be that the power utility pay the capital cost ($60,000,000.00 for ten 20 MW units, instead of $200,000,000.00 for one 200 MW unit), and

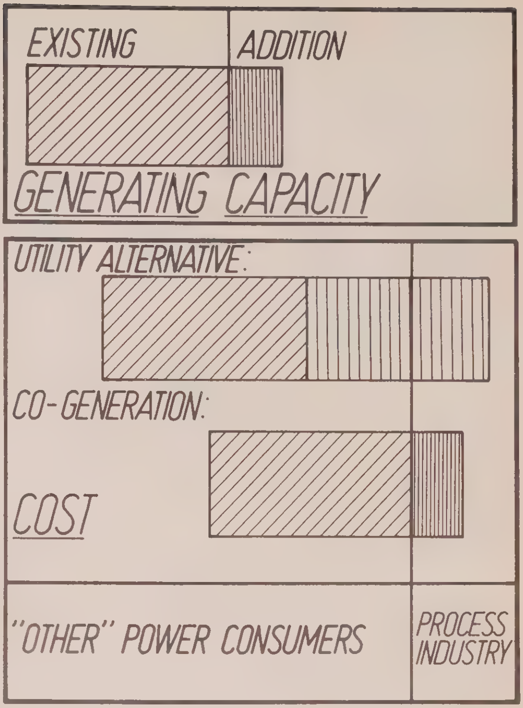


Figure 4

that the industries pay the utility 15% of the capital cost each year for 12 years (at which time the capital has been paid off with 10% interest).

The initial cost for the industry in 1980, including capital cost (if the decision is made today), would be 1.93¢/kWh and by 1985 the cost would be 2.6¢/kWh. This is of course to be compared with my earlier assumption that purchased power would cost 3¢/kWh and the fuel would cost $4.00/MM BTU in 1985.

The utility would have saved $140,000,000.00 in investment money, and with fewer "new" single-purpose stations on the network, the average utility power cost will be lower.

It would also be simpler for the utility to provide stand-by power for ten 20 MW units than for one 200 MW unit. Simply expressed, for ten 20 MW units it is very unlikely that a total of 200 MW stand-by power would have to be supplied at any time.

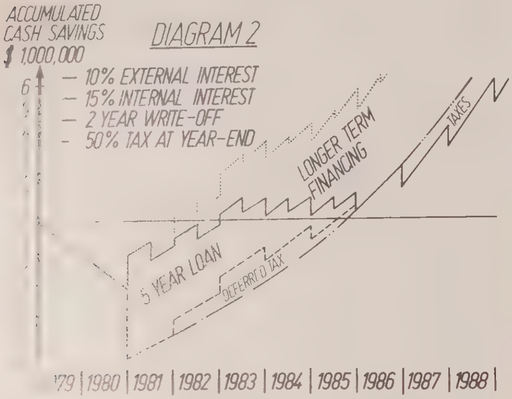
Now, one should probably not expect the utility to provide the investment money, but power generation capacity should be financed with some type of long-term financing, arranged separately from the financing of the normal industrial operation.

A rough estimate could include the following assumptions:

— A decision today to install a 20 MW back-pressure unit.
— Internal interest 15% on invested cash.

- A five year loan for 75% of the investment cost to be paid off with semi-annual installments (10% interest).
- Full utilization of the allowable 2-year write-off for tax purposes.

For a 20 MW plant with a total investment cost of $6,000,000.00, the result would be as follows: (DIAMGRAM 2)



...he external funds borrowed at the time of the ...ion. the cash investment would be limited to ...00.00

...saving during the first year of operation (1981) ...be $1,100,000.00 (compare with diagram 1), but ...the year two payments on the external loan ...y $1,300,000.00 including interest and capital), ...ld give a negative cash flow. However, utilizing the ...ibility of a two-year-write-off of the investment ...for tax purposes), one would make a book loss of over $2,000,000.00 during the first year, which would give a tax benefit of $1,000,000.00

Applying the balance of the write-off for 1982, all cash would have been returned after two years of operation (and $1,800,000 of capital would have been paid back on the external loan).

During the next three years of operation (1983-1985) the annual saving could be used to eliminate the external loan completely (and to pay the deferred taxes to the government).

A longer term financing would result in the return of all cash after one year of operation, followed by generation of cash (for other investments) during the following years.

The long-term financing of a turbine generation installation can be motivated by the fact that it is a safe investment. Electric Power will always be in demand, while the demand for industrial products fluctuates. A turbine generator installed now will make it easier to survive a low industrial product demand period in the future because the cost of producing the products will be lower.

THE FIGURES USED ABOVE ARE BASED ON ASSUMPTIONS WHICH IN TURN HAVE BEEN MADE FROM VARIOUS TRENDS AND ESTIMATES. THE PURPOSE HAS NOT BEEN TO PROVIDE EXACT FIGURES BUT RATHER TO PROVIDE SOME IDEAS ON HOW TO EVALUATE COST FIGURES THAT WILL BE PROVIDED BY OTHER SPEAKERS DURING THIS SEMINAR.

My guess is that my assumptions have been conservative. In addition, increased use of coal, bark and hog fuel will lower the cost for future back pressure power generation. This cogeneration principle not only saves fuel, but can also use low grade types of fuel.

Back pressure power plants do also keep other development possibilities open. One future possibility is the addition of pressurized fluidized bed combustion of coal. (FIGURE 5)

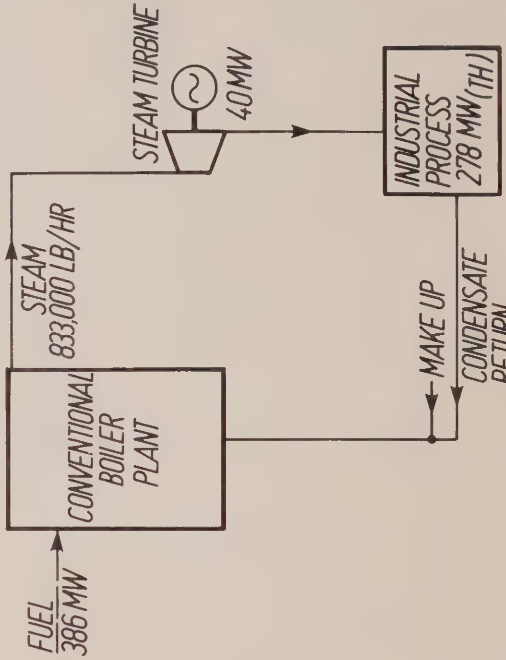


Figure 5

In an actual case, which has been studied, the industrial process uses 278 MW of process heat and provides today the possibility of generating 40 MW of back-pressure power. The steam pressure used by the process is relatively high, which explains that the potential is limited to 40 MW. Fuel corresponding to 386 MW would have to be supplied to the boiler. (FIGURE 6)

Some time in the future, it is possible to replace the conventional boiler with a gas turbine unit with a pressurized fluidized bed combustor. The combustor would be fed with crushed high sulphur coal (and with crushed limestone for absorption of the sulphur).

Steam is raised in tubes which are immersed in the fluidized bed. Due to the relatively low combustion temperature, high temperature corrosion is eliminated

and the fluidized bed provides a very good heat transfer coefficient. The dimensions are small, thanks to the elevated pressure. The heat value of the coal supplied to the fluidized bed would correspond to 473 MW (which is 87 MW more than the fuel supply to the conventional boiler), but the gas turbine unit (used for pressurizing the combustor) will give 70 MW of electric power, which means that the gas turbine power is generated at 80% efficiency.

The second stage of the development work towards a demonstration plant at TIDD generating station on American Electric Power's (AEP's) network, started earlier this Fall, and the first gas turbine of this type, with PFB-Combustor, would be in operation in the 1980's.

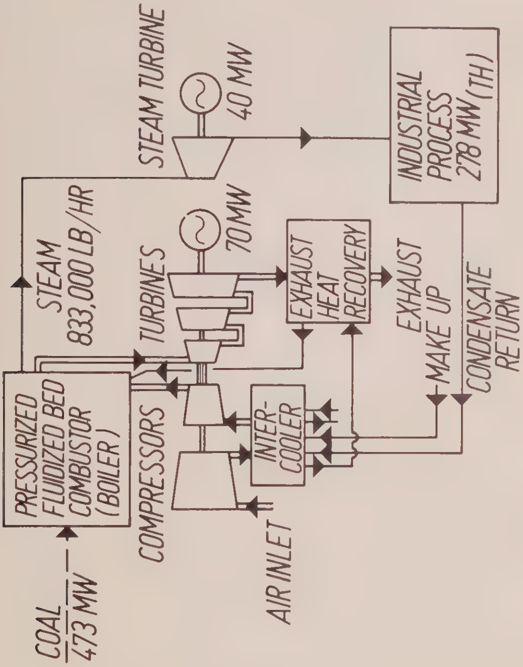


Figure 6

Discussion:

Which Alternative is the Most Advantageous for Industry

SVEN ERLANDSSON (ASEA)

Question: **C. Planzer,** *Dominion Textile*

In your first slides, you had some capital costs of about $1,000 per megawatt capital costs for the conventional boiler type and about $300 for the cogeneration. Would this be comparable, that is including all the boilers, turbines, transmission controls, or is this for only part of the equipment that would already be used in the plant?

Answer: **Mr. Erlandsson**

I would say that the $1,000 per kilowatt for a 200 MW coal fired station is probably underestimated. That would, of course, include all costs for the plant because everything at the plant is necessary for generation of the power. At the back pressured power plant the assumption was that there is a steam plant in any case, and there has to be a low pressure boiler supplying the process with the industry, and included in the cost was the incremental cost needed to bring that steam station up to back pressure power station.

Question: **Peter Zaharuk,** *Falconbridge Mines Ltd.*

What state is the development of the pressurized fluid bed boiler at now?

Answer: **Mr. Erlandsson**

A fluidized bed pilot plant has been operated in the U.K. for a number of years, and various tests have been made with coal and limestone fed into it. Also with the exhaust from that bed turbine blades have been installed. Certain studies have been made on what effect the dust will have on the turbine blades, eg. different kinds of dust removals are studied. Regarding the gas turbine, there is an existing oil fired gas turbine in which the outside combustors can be removed and the unit is principally as it is, instead of being connected to the back.

Electrical Requirements for Parallel Operation of Cogeneration and Hydro System

A. GUSEN
Manager, Regional Supply Planning
Ontario Hydro

Ontario Hydro has, for many years, served customers having on-site cogeneration operating in parallel with the utility system. There are several distinct advantages to the customer from parallel operation with the utility. However, some operating, protective relaying, and possible short-circuit infeed problems result from this type of operation, and its resolution depends on the clear understanding of the operating requirements of the Ontario Hydro System, and the costs involved in the design of the parallel operation equipment and its circuits.

I welcome the opportunity to take part in this timely seminar on "The Economics of Industrial Cogeneration of Electricity". I hope you will find my input useful and practical.

In Ontario, as in the settled portions of most of the other provinces, the usual pattern has been for industries which generate part of their own electric power to operate their generation in parallel with the electrical utility. The alternative is, of course, to split the industry's electrical load into two parts, one carried by its own on-site generation and the other by the utility; or in some cases to supply the entire load normally from on-site generation, with the utility connection treated as a normally-open standby source.

Ontario Hydro has, for many years, served customers with on-site generation which operates in parallel with its system. There are several distinct advantages (and few disadvantages) to the customer from parallel operation with the utility.

In the past, while Ontario Hydro has not promoted on-site generation, it has not discouraged parallel operation where the customer found on-site generation to be to his advantage and decided to install it.

Some of the important *advantages* of parallel operation are as follows:

To the Customer

— Stable frequency
— More stable voltage
— Eliminates or reduces problems of starting large motors and applying them to fluctuating mechanical loads.
— Permits on-site generators to be operated at optimum output, determined by changing demands for steam and electric power.
— No loss of load if on-site generator(s) trip off, provided substation and plant distribution system, *and* the utility's supply facilities, are designed to handle the resulting loads.
— In most cases, it would be possible to carry at least the loads essential to human safety and orderly shut-down, if the utility supply is interrupted. This requires that the plant distribution system be suitably designed to automatically shed non-essential loads, and that the on-site generating units be equipped with modern, fast-response governors and voltage regulators.
— If the output of the on-site generation periodically or regularly exceeds the customer's load demand and is at relatively low cost per kWh, there is the possibility of mutually advantageous sales of excess energy to the utility.

Advantage to the Utility

— Possible purchase of excess energy from the customer at a lower cost than the utility's marginal cost of production.

Advantage to Both Parties

— Encourages energy conservation, by maximizing benefits to customer of on-site generation.

The disadvantages of parallel operation which come to mind are as follows:-

— Increased short-circuit duties. This could be the most costly problem to deal with, particularly in cases where the customer has a number of circuit breakers at generator voltage which are already subject to short-circuit stresses and interrupting duties close to their ratings.
— There will invariably be *relatively* small additional costs for relay protections and synchronizing facilities. (I do not count the additional circuit breaker(s) or other means of automatically dropping non-essential loads if the utility supply is

lost, since this feature would only be provided if the expected benefits outweighed the cost).

- Some risk of damage to the on-site generator through faulty synchronizing. (If there are more [illegible] one on-site generator, this risk is present even without parallel operation, with the utility. However, the stresses would be greater with parallel operation due to the higher short-circuit [illegible]

Disadvantages to the Utility

- [illegible]ls to utility's operating and maintenance [illegible] possibility of supply circuit being [illegible] from customer's on-site generation [illegible] circuit was thought to be dead.
- [illegible]t-circuit duties at the supply [illegible] station. It is difficult to generalize, [illegible]r's total on-site generator capacity [illegible] less would not often create a pro[illegible] there are already appreciable short-[illegible]ds to the transformer station bus [illegible] generation or large motors.
- [illegible] reclosing of supply breakers after a [illegible] be delayed to ensure that the on-site [illegible] has been automatically disconnected. [illegible] could have an adverse effect on supply [illegible] customers. This problem can be over-[illegible] by remote tripping from the utility's supply [illegible] the customer's substation, using leased [illegible] circuits or other communication [illegible]
- [illegible] feeder protections at the utility's supply [illegible]ation may have to be slightly more complicated [illegible]irectional overcurrent relays, no-voltage super-[illegible]ion of manual and automatic reclosing).
- [illegible]f the customer could feed power back to the util-[illegible], intentionally or otherwise, the billing metering becomes more complicated. If it is a regular, planned backfeed, the contractual arrangement also becomes more complex.

Additional Costs Arising from Parallel Operation

Increased short-circuit duties on customer's equipment

It is not possible to place a general dollar value on such additional costs. They can be zero in the case where a small generator of 1000 to 2000 kVA is being added in a modern plant (in which the switchgear, motor starters and buswork have a good margin over the existing short-circuit duties). On the other hand, these additional costs can run into tens or even hundreds of $1,000's, where one or more larger generators are being added or the plant distribution system's ability to withstand and interrupt the previous short-circuit levels was marginal.

In such cases, it is necessary to add current-limiting reactors in strategic locations. It may also be necessary to replace some of the switchgear by equipment with higher interrupting capability and to strengthen some of the buswork against the higher short-circuit stresses.

It should be remembered that some of this upgrading of short-circuit withstand and interrupting capabilities would probably be needed sooner or later as the plant load expanded, even without infeed from the on-site generation.

Increased short-circuit duties at utility's supply station

As for the problem on the customer's distribution system, which has just been discussed, it is not possible to place a general dollar value on the additional costs at the utility's supply station. As already mentioned, a total generator capacity of up to 5000 kVA in one or more units, and with the utility supply being at 13.8, 27.6 or 44kV, would probably not create a short-circuit problem at the utility's transformer station supplying the customer.

Exceptions to this statement would be a few transformer stations in areas of heavy industry, where shortcircuit infeeds from synchronous machines had already raised the short-circuit level close to its design limit (Ontario Hydro) (500 MVA at 13.8 kV, 800 MVA at 27.6 kV, 1500 MVA at large 44 kV transformer stations).

Where a short-circuit problem was found to exist, either because the customer planned to install large machines or because there were already substantial shortcircuit infeeds from large motors and generators, solutions to the problem could become quite costly. Since the benefits of parallel operation accrue almost entirely to the customer, I believe I am correct in saying that he would be expected to pay for the remedial measures by the utility. This would clearly be the case where his equipment was responsible for most of the shortcircuit infeed from the loads to the supply station.

Where the customer contemplating on-site generation with parallel operation is already supplied at 115 kV or 230 kV, a much larger generator (or group of generators) should not generally cause short-circuit problems on the utility's 115 kV or 230 kV system.

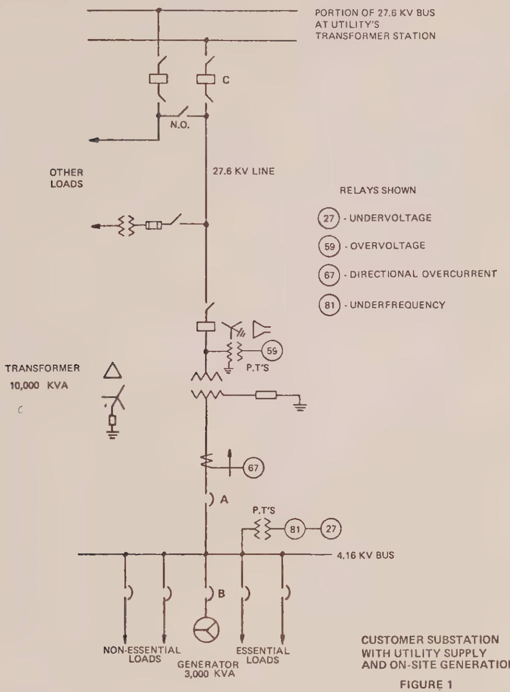
Cost of Additional Relaying and Synchronizing Features due to Parallel Operation

As mentioned earlier, these costs are relatively small, and unlike the possible costs of dealing with increased shortcircuit duties, are reasonable predictable. The cost estimates presented in this paper include only 1978 engineering costs, equipment and material costs (including Federal and Provincial Sales Tax), and labour costs. The estimates do not include overheads, contingencies, or interest charges, since these vary widely from one organization to another.

The estimates assume that existing instrument transformers have sufficient volt-ampere capacity to handle the additional burdens and, except where otherwise noted, that panel space is available for the additional relays. The engineering costs used are quite high because they assume that existing installations, designed for utility supply only, must be modified for the addition of on-site generation.

Some of the additional costs would apply to nearly all cases of onsite generation operated in parallel with the utility system, while other extra costs would only apply to a large generator or to a single generator installation operated in parallel with the utility.

The arrangement assumed for estimating purposes if shown in Figure 1.



CUSTOMER SUBSTATION WITH UTILITY SUPPLY AND ON-SITE GENERATION

FIGURE 1

The estimates of typical additional costs applicable in nearly all cases are a follows:

1. **At Customer's Substation**

(a) Directional overcurrent relay scheme to trip breaker A (or breaker B) for phase-to-phase faults on source side of breaker A.

(b) Overvoltage relay scheme to trip breaker A (or breaker B) for phase-to-ground faults on utility supply line (includes cost of three 16-0.120 kV P.T.'s connected)

Note: If breaker A is tripped from protections (a) and (b) it would also be desirable to trip sufficient non-essential load to allow generator to continue to supply essential loads.

(c) Underfrequency and under-voltage relay scheme to trip breaker B (or breaker A and non-essential loads) for loss of utility supply.

Total cost of 1(a), (b) and (c) with relays mounted on new panel	$34,000
(d) Synchro-check relay scheme to supervise closing of breaker B when synchronizing generator to utility system	$5,000

2. **At Utility's Transformer Station**

No-voltage supervision of both manual closing and automatic reclosing of 27.6 kV feeder breaker C (includes cost of one 16-0.120 kV PT connected line to ground)	$7,000
Total estimated cost of additional protective features	$46,000

The estimates of additional costs which would apply only in certain circumstances are as follows:

3. **At Customer's Substation**

(a) Synchroscope and two indicating voltmeters mounted on new panel; add one 4.16-0.120 kV PT	$10,000
— This equipment would be chargeable to parallel operation if there were only one on-site generator.	
(b) Synchro-check relay scheme to supervise closing of breaker A .	$5,000
— This feature would only be needed if the arrangement was for the generator to continue to supply essential loads when utility supply was interrupted.	

4. **At Utility's Transformer Station**

(a) Replacement of nondirectional instantaneous and inverse-time phase fault protective relays by directional protections on 27.6 kV feeder position C.	$12,000
— This would only be needed for larger onsite generator capacity, where its shortcircuit infeed to the transformer station bus exceeded the pick-up setting of the non-directional low-set relays.	
Total estimated cost of additional features which would only apply in certain circumstances	$27,000

List of References re Parallel Operation and General Comments

In preparing this paper, I tried to locate other papers and reference texts on the subject of parallel operation between customer-owned local generation and the electricity supply utility. I am presenting the following comments on these references which I thought to be relevant.

1. **IEEE Guide for Protective Relaying of Utility-Consumer Interconnections**

   IEEE Standard 357-1973
   ANSI Standard C37.95-1974
   This guide gives an excellent overview of the need for close coordination of the utility's and customer's relay schemes, and the need for the customer to recognize that voltage dips and transient overvoltages are "facts of life" which must be allowed for in the design of his electrical system.
   While it does not deal at length with relaying problems peculiar to on-site generation, Examples 4 and 5 do cover this situation in elementary form.

2. **Industrial Power Systems Handbook**
   Donald Beeman - Editor
   McGraw Hill Book Co.

   This handbook will be familiar to many of those present. Chapter 15, "Modernization and Expansion of Existing Power Systems" includes a number of cases where one or more generators are being added to an existing plant distribution system. Various means of controlling short-circuit duties on existing lower voltage (480, 600 or 2400 V) equipment are presented.
   Chapter 16, "Steam and Power Generation", deals with the following:

   — Trends in the usage and source of power for industrial plants.
     Factors to consider when purchasing power.
   — Comparison of industrial power plant cycles
   — Other sections dealing with steam, gas turbine and diesel engine plant cycles, efficiencies, etc.

   Under "factors to consider when purchasing power", which is quite brief and general (5 pages), the following headings will give some indication of the subject matter:-

   — size of load vs. power available
   — always give the utility the full story early
   — power supply for critical processes
   — voltage regulation
   — master unit substations
   — separate utility and industrial plant operations
   — parallel operation of generating facilities
   — relay coordination.

   It is of interest to note that under "parallel operation" the Handbook states:- "When the industrial plant generates part of its own electric power, and purchases the rest from the utility system, it is always highly desirable to operate the generating facilities in parallel to obtain the most flexible operation for both the utility and the industrial plant."
   One drawback of this handbook is that it is still the First Edition, printed in 1955, as far as I have been able to check. Thus some of the material may be a bit dated.

3. **The Technical Problems Posed by In-Plant Generation in Industrial (Particularly Chemical) Power Systems. Factors to be Considered & Studies to be Made (Paper No.6.3)**

   International Conference on Electricity Distribution (CIRED)
   London, England, 23-27 May 1977.

   IEE Conference Publication No. 151
   Part 1 - Contributions
   The four authors of this paper are from Milan, Italy. Their Figure 1, which is Figure 2 of this paper, shows a typical large chemical plant. In Section A, the 85 MVA on-site generator has enough capacity to carry nearly the entire load including 42 MW and 16 MW groups of induction motors. Automatic load shedding of non-essential loads is provided.

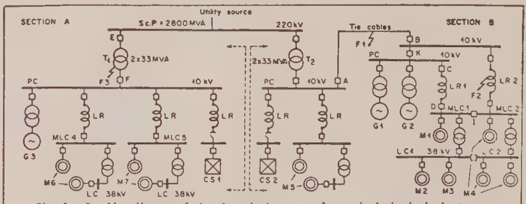


Fig. 2 - One line diagram of the electrical system of a typical chemical plant.

LR=Limiting reactor
PC=Power Center
MLC=Master Load Center
LC=Load Center
G1-G2:23÷29MVA
G3:85 MVA cosϕ=.85
Static exciter: KA=50 p.u.
Vceiling=±3.5 p.u.

$$\left.\begin{array}{l}\mathbf{M1=21MW}\\ \mathbf{M2-6MW}\\ \mathbf{M3=3.5MW}\\ \mathbf{M4=15MW}\\ \mathbf{M5=10MW}\\ \mathbf{M6=42MW}\\ \mathbf{M7=16MW}\end{array}\right\}\ \textbf{Pump and compressor induction motors}$$

CS1=27MVA cosϕ= .87
CS2=12MVA cosϕ= .87

In Section B, the total essential load (induction motor groups M1, 2, 3) appears to be 30.5MW while generators G1 & G2 total 52 MVA. Thus

the generators can carry these essential loads if the utility supply is interrupted. Motor groups M4 (15 MW), M5 (10 MW) and load CS2 (MVA) are considered less essential. Breaker I is normally open.

If the outside supply fails, then breaker K is opened automatically to supply essential loads M1, 2 and 3 from G1 & G2. To reduce transient disturbances, the current through breaker K should normally be near zero.

The paper stresses the importance of using sophisticated stability and transient computer programs "to verify that transient or dynamic instability conditions are avoided" and "pointing out the influence of load behaviour (induction motor stalling) and any programmed load shedding or motor restarting."

The paper goes on to say that:-"even programs with sophisticated representation of generators with their excitation and governor systems, but with rough representation of motors" . . . "give in many cases unreliable results".

Figure 2 of this paper (my Figure 3) shows the results of some of these sophisticated computer studies. A fault in the 10 kV cable connection between the utility supply and the G1-G2 bus is assumed to be cleared in 0.12 seconds.

Case 2 shows bus voltages and motor speeds with a static exciter ceiling voltage of ±3.5 p.u. Case 3 shows these quantities with a [illegible] exciter ceiling voltage of ±10 p.u. It will be noted that, in Case 2, all the motors are going to stall while, in Case 3, they have recovered [illegible] speed in 0.6 seconds.

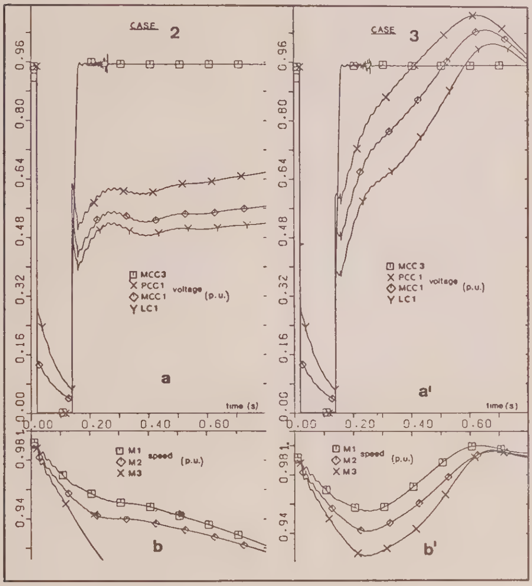


Fig. 3 - a.c. component of voltages (a-a') and speed of motors (b-b') for cases 2 and 3 to Table 3.

I did not make a really intensive sear[illegible] literature, but a number of other references which our Library located for me were very gene[illegible] shed too much additional light on th[illegible]

Conclusion

Some operating, protective relaying a[illegible] shortcircuit infeed problems will result from o[illegible] of customers' on-site generation in parallel [illegible] tario Hydro's system. These problems ha[illegible] resolved in the past by cooperation amon[illegible] customer's technical and operating staff, his con[illegible]tant and Ontario Hydro. Hydro will continue [illegible] cooperation to help encourage conserv[illegible] energy resources and other benefits to the [illegible] which result from parallel operation of his [illegible] generation with the electrical supply systen[illegible]

Discussion:

Electrical Requirement for Parallel Operation of Co-Generation and the Hydro System

A. GUSEN

Manager, Regional Supply Planning Ontario Hydro

Question: Mr. McCullum, *Westinghouse*

From your talk, I take it that Hydro has a clear-cut policy of entertaining proposals for self-generation of involved parallel operation with Hydro, and feedback of power to Hydro. Is this to be seen as only in the context of connecting to Hydro's own tr[illegible] sion lines, or does this include a policy applicable [illegible] municipal electric systems?

Secondly, what is the policy position of Hydro on wheeling electric power from let us say a co[illegible]

generation of a subscriber to another plant property owned by the subscriber or perhaps owned by a second party?

Answer: Mr. Gusen

Well, in answer to the first question, my experience has been mainly with cases where the customer was connected through Ontario Hydro facilities, but not entirely. Stelco in Hamilton comes to mind where they have local on-site generation which is connected through short sections at least of Hamilton Hydro cables. I think with proper safeguards I am sure that that cooperation would also apply if the industry was a customer of the municipality. The second part about wheeling power from one plant to another; I don't believe I have encountered a case of that so I can't say what the policy would be. I think we'd have some reservations but perhaps Hedley Palmer, who is the next speaker could comment on that.

Question: Mr. McCullum

If I could just comment on the first part of my question again, perhaps I'm out of touch with some of the positions of municipal electric authorities, but generally their reaction is that we're allowed to buy power only from Ontario Hydro; we are not allowed to buy power back from subscribers. Now that may be past history, but that's really the basis of that question. From your answer I take it that the policy position of Hydro is, that subject to satisfaction of safe-guarding the integrity of the system, they will entertain proposals.

Answer: Mr. Gusen

Well, I guess I misunderstood you. I thought you were talking about the case where the customer wasn't generating enough power to exceed his demand and would be selling it back. We've had few, if any, such cases in the past, but I think you're right though, that there are some municipalities that have their own hydro plants, and that we have certain rules and regulations from the Power Corporation Act about how they're to operate those. We certainly don't prohibit that. But I do believe there would be some problems if the industry had an excess of power and was selling it to the local utility. I can't answer that offhand, but I think there would be some legal difficulties. Ontario Hydro does buy power when it's surplus from industry, and certainly that arrangement could be made through the utilities' system, but whether the utility could buy it, I think there would be some legal problems there all right.

Question: Mr. McCullum

Surely most of the cogeneration prospects are in an island of municipal authority and if they can't connect to the municipal, what is the point of a cogeneration that may involve or may depend, to achieve efficiency, on selling power back to the utility? Now this is really a very real prospect when you consider the wide variations in temperature in this province. If you're going to look at gas turbine generation in cold weather, you have great gobs of surplus power capacity in the winter, and the whole efficiency equation depends on delivering that power into some heat sink, and to a lesser degree this is true with back pressure steam turbines, where cold weather usually brings on a demand for more steam because of heating as well as process and therefore, you have the capability of generating more power. So it's a real problem in the process of examining the economics of cogeneration. The power is going to be there - how do you get rid of it and how do you deal with your municipal utilities? The Hydro position seems clear, but how about these fellows that the customers are really dealing with?

Answer: Mr. Gusen

I think the problem could be resolved whether the excess energy was being sold to the municipal utility or to Ontario Hydro. I don't see any technical difficulties. One organization or the other would be quite prepared to buy it, if it was being generated at lower cost than the incremental cost of our own production.

Answer: Dr. Ian Rowe, *Ministry of Energy*

I think the questioner from Westinghouse is asking a very valid question. I would like to say we wouldn't want to confuse the historical reasons for the impediments as he would view them in the Power Commission Act to what is possible. We've had both Legal Counsel and Ontario Hydro look at the specific issues, and identify the customer to the municipality, the customer to Ontario Hydro, the customer wheeling through the municipality and the customer wheeling through the Ontario Hydro system. I agree there are certain impediments, but I would also say that there is a completely open mind about removing some of these. Something could be done with simply waivers, other suggestions are changes in the Power Corporation Act and, as the Minister said this morning, we have a completely open mind with respect to that. You see, some of the reasons that those impediments exist have been trying to keep the basic principles of safety and regulation and of power at cost to all Ontario users in some kind of proper perspective, and if a new opportunity comes along, I don't see any particular difficulty of accommodating that in the quite short term.

The question for example of wheeling, is simply a matter of contractual arrangment, and that's already now being examined by Legal Counsel of Ontario Hydro and one of the co-generators in the province. There are no institutional impediments that the Minister would allow to stand in the way of anything that benefits Ontario industry utlimately.

Question: Al Thom, *E. B. Eddy Forest Products*

Unless you're selling through the municipal authority to the Hydro, they wouldn't want to buy it because they're still paying for the peaks again. It all goes back to this peak we're paying Hydro, and there is no use them buying excess power if they're still going to get nailed for the peak, because that's quite a big chunk of your money.

Answer: Mr. Gusen

Yes, I agree. We can be very positive about any surplus energy. I mean that's clear cut, but paying for peak of course depends on the long-term availability and with our long lead times, it doesn't do any good to have — for instance, this year we've got peak power running out of our ears, and buying peak from an on-site or cogeneration plant would be of practically no value at all. Ten years from now it might be, but we'd have to be assured of it being available when we needed it to at least the same degree as our own generation, or we'd have to pay some lower price for it in fairness to all our other customers, to try and be equitable to everyone.

Cogeneration Rates and Rate Structure for Industrial Cogeneration Installations

H. C. PALMER
Ontario Hydro

Because cogeneration enables industry to replace purchased electrical power with in-plant generated power, a cogeneration plant is more attractive where the electrical rate is high and the cost of industrial fuel is low. Since the electrical rate plays an important part in the make-buy decision, this paper will review the present rate structure affecting the cogeneration systems and will also discuss the trends in this field for the near future.

Today's emphasis on conservation, dwindling energy resources, efficiency of use and ever-increasing prices have tempted users to squeeze every BTU a unit of fuel can provide. Hence, the rejuvenation of interest in cogeneration facilities.

A cogenerator can sell all, some or none of its electricity back to the utility grid, and can purchase all, some or none of its on-site electricity needs. Each of these may result in a different configuration of rates and means of determining them.

I propose to look at this broad subject from three more narrowly defined perspectives.

Firstly, we have those industries which may through cogeneration generally provide some portion of their own electrical needs and require Ontario Hydro to provide the balance of their requirement to meet their total demand.

However, depending on the circumstances and the customer's cogenerating stability, these industries also may have excess electricity to feed back into the grid from time to time.

Secondly,there are those industries which through cogeneration may develop an electrical output surplus to their own basic needs. This type of firm may wish to sell its excess electricity to Ontario Hydro on a long term firm basis.

And thirdly, there are those industries where it may be of mutual benefit for Ontario Hydro to make a joint venture investment to provide on-site cogeneration.

In the energy daily of August 17, 1978, The National Association of Manufacturers Task Force said "utilities tend to establish rate schedules and rules of practice and procedures that burden potential cogenerators." Apparently, this burden includes charging too much for stand-by power, paying too little for excess power, prohibiting any form of self-generation and refusing to or showing reluctance to wheel power over its lines. As I move through the present Ontario Hydro policies and rates, you may want to form a judgement as to what the position of Ontario Hydro is to this general condemnation. To help you in doing this I will go through each of the three cases I have outlined in some detail.

I will begin with the first type of co-generation facility where some cogenerated electricity is produced but usually at an amount being not enough to meet the customer's total electrical requirement.

In Ontario, there are about 30 establishments generating electricity, of which about a dozen are interfaced with the Ontario Hydro grid. As might be expected, among these customers are the major pulp and paper companies who have access to hydraulic generation. However, other major methods of generation include the steam topping turbine, the gas combustion turbine and to a lesser extent, the diesel powered engine.

To this point in time, all industrial type onsite cogeneration installations have been made based on the processing needs and economics of the customer where the projects feasibility was established without regard for the sale of excess energy to Ontario Hydro. By reason of possession of his own generation, this customer is likely to be somewhat different than other industrial customers of the same size. Accordingly, the interface between the industrial cogenerator and the utility has to date warranted individual attention. In those instances when the customer is able to produce more electrical energy from its generation than it can use and the company desires to sell it to Ontario Hydro, appropriate arrangements have been negotiated. Generally these arrangements have been completed on the basis of equal sharing of the resultant

operating savings to Ontario Hydro, that is by combining the cogenerator's incremental production cost with the incremental production cost of Ontario Hydro and dividing this amount in half to determine the rate for such surplus energy.

In this case, incremental production cost is defined as "any cost incurred by one party supplying energy to the other, which would not otherwise be incurred if the transaction did not take place".

The incremental production cost might include such things as incremental fuel, maintenance, labour, transmission, taxes, production, boiler firing-up cost, and so on.

It should be acknowledged that the approximate sharing of costs as just described generally assumes that the cost of electrical energy produced by the industrial customer is less than that of Ontario Hydro.

However, should the circumstances result in the sale of surplus energy at periods when Ontario Hydro's costs are **lower** than the cogenerators, Ontario Hydro will still consider the purchase based on Hydro's costs at the time, less 10% for administration. Of course, this may still be of some financial advantage to the industrial customer.

Just as this surplus energy may only be available from time to time for feedback into the grid, this customer may also encounter a standby requirement from time to time. Accordingly, Ontario Hydro accommodates this latter consideration through a standby rate.

Short-term deficiencies on the customer's generating system necessitating a standby rate may be caused by:

(A) A failure of the customer's generation facility
(B) External influences on the customer's generation facility such as unfavourable water conditions
(C) A reduction in output to provide for generating plant maintenance.

In this event, assuming it is the customer's desire to contract for standby service, there is a charge based on the customer's billing demand of standby service being determined as the **greater of**:

(A) 10 percent of the customer's installed generating capacity
(B) The capacity of the customer's largest generating unit
(C) Notwithstanding (A) and (b), some other negotiated level which could be influenced by such things as capacity limitations of either the customers or Hydro's equipment.

Currently in 1978, the charge for this type of standby service to a co-generator is:

(A) 115/230 KW 65¢/KW/MONTH
(B) UNDER 115 KW 80¢/KW/MONTH

Correspondingly, the **normal** monthly demand charge in 1978 is $4.46 and $4.67 per KW for each of these demands.

The monthly standby charge of $8 to $10 per KW per year specifically provides the customer with the standby service option if and when it may be required. Failure by the customer to contract for standby service may deprive it of this option should the need arise, simply because Ontario Hydro may not be in a position to readily supply it.

The standby charge is based on a weighting of each of the functional components comprising the normal demand charge.

It should be clear that Ontario Hydro's regular monthly demand/energy rate is applied in addition to this standby charge, should the customer in fact draw some standby power in any one month; however, the regular monthly demand charge is waived in those months when no standby power is taken.

The determination of an appropriate standby charge that best reflects the various circumstances is not a critical consideration at this time bearing in mind the magnitude of standby power now required. However, this matter will warrant a more in depth analysis in the future as the extent of cogeneration increases. Should the amount of standby service increase substantially, it may be necessary to account for it in setting generation reserve levels and this could result in higher standby rates.

Outside Ontario Hydro, the approach of some utilities to standby charges has been to waive the energy component and maintain the full demand component intact. This approach may not be entirely appropriate. It has been suggested by some that consideration be given to assigning a probability factor to the amount of load and the timing of a standby requirement and on this basis, appropriately prorate the otherwise full demand charge.

Time differentiated rates may, if implemented also have some impact on the standby rate. While a large standby requirement on-peak may warrant a relatively high standby charge, conversely, a smaller off-peak requirement would warrant a lower standby rate. Time differentiation by seasons may show the cost of standby varies by seasons as well.

Depending on the potential cogenerator's ability to manage his load and the reliability attached would affect the level of standby charge and may influence the entire feasibility of a cogeneration facility.

In addition to the just described cogenerator who operates his system in parallel with Ontario Hydro and chooses to contract and pay for standby service, there may be the cogenerator who may choose **not** to pay for the standby service as just described. In this latter case, the normal minimum billing provision of 75% of the highest peak in the previous 11 months is raised to 90%. This will allow the customer to deviate 10% from his highest peak in the previous 11 months. If the customer falls outside this limit, he will be faced with a charge of 125% of the normal charge, in which case it may be prudent for the customer to consider a contract for standby service.

With respect to the matter of standby service, in contrast to the customer whose facilities are operated in parallel with those of Ontario Hydro, there may also be a cogenerator whose facilities are **not** operated in parallel. Being a cogenerator, and likely lacking back-

up reserves, this customer may also require standby power if his system is down for an extended period. In this latter instance, a specific sale may be negotiated between Ontario Hydro and the customer for the supply of its short term requirement at 125% of the normal demand charge.

If I may, while on the subject of standby rates, I would like to deviate to the **residential** sector for a moment.

Solar energy, while not competitive in the generation of electricity under existing conditions, is apparently economically feasible for hot water and space heating applications in the residential sector. In this instance, because solar systems are not necessarily designed to provide 100% of the heat required, standby electricity is necessitated. Solar space heating offers a special challenge to electrical utilities in northern climates because substantial standby may be required. Also it may be required while the power system is peaking. Coupled with this the actual energy provided is less than for normal service. What this adds up to is that the solar heating customer, if he is to reimburse the utility for his own cost of service, will have to pay rather high standby charges. The alternative is to pass these charges along to other customers in their rates. To date we have not come to grips with this problem and such customers are served at standard rates. For the moment there are very few solar heated houses so the inherent subsidy in this practice is very small so no great harm is being done at the moment.

Currently, Ontario Hydro is in an experimental stage with this type of farm and general service customer using windmills, water wheels and solar conversion. As I noted a moment ago, standard rates are applied with the standard minimum charge applicable to the monthly billing. The charge however, is levied on the net energy supplied by the utility with the qualification that the net energy cannot have a negative value. We have one windmill on the system using a synchronous inverter for parallel operation. We are currently collecting test information.

In summing up standby service, it is our intention to review the whole area of standby rate structures and levels considering all the numerous implicating circumstances.

I will now elaborate on the second of the three perspectives described at the outset of this paper.

While cogeneration basically may be defined as the sequential production of electrical or mechanical power and useful thermal energy from a single fuel output, there have also been cases where private enterprises have wished to undertake the building of more extensive generation facilities to capitalize on the production of a by-product supplemental (externality) to the basic product. This desire could be precipitated by a variety of reasons such as the need to burn wood wastes, etc. In this regard, a panel will be addressing the "Hearst Study" later today.

The economics of such ventures are very much dependent on the sale of electricity to Ontario Hydro. Since these kinds of operations could supply power and energy to Ontario Hydro on a regular and reliable basis, "capacity" payments in addition to energy payments would appear to be in order. To qualify as "firm" capacity, it would have to be available with a high degree of reliability to supply peak loads at least 16 hours per day during daytime, 250 or more working days per year.

In such cases, if "firm" capacity were committed to Ontario Hydro, it is felt that a pricing policy for capacity payments should be based on the true cost benefit associated with Ontario Hydro not having to install an equal amount of fossil-fuelled generation.

Ontario Hydro's future load and capacity situation is uncertain and, based on current projections of load and generation already under construction, a surplus of generation is expected until the late 1980's. It is therefore estimated that until 1988, very little credit can be given to additional generation. In 1988 when new facilities may be required, the credit is estimated to be \$70/KW per year (in 1988 dollars), possi[illegible] escalating at 5% or 6% per annum. This credit, a[illegible] as the number of years in the intitial "no-v[illegible] will probably change in time. They are menti[illegible] as rough indicators only.

It is acknowledged also that this approximate credit may not in itself be sufficient to create any t[illegible] cogeneration initiative at this time. It does [illegible] provide some measure of what the nece[illegible] couragement will cost to facilitate the m[illegible] needed to have cogeneration in place when it i[illegible] to the system.

It appears that the determination of capacity payments for cogeneration will be complex, in that [illegible] will have to deal with lead times for construction an[illegible] for commitment of cogeneration capacity to Ontario Hydro, as well as the lead time for construction of [illegible]tario Hydro generation. It will also have to deal [illegible] reliability, production schedules, and possibly [illegible] geographical location of the cogeneration [illegible] framework we are looking forward to an invig[illegible] exchange of thoughts to assist in the formu[illegible] policy.

Turning now to the last of the three perspectives, there are situations where Ontario Hydro might entertain a joint venture.

At the moment, Ontario Hydro does not have any projects of this nature in-place.

However, Ontario Hydro is willing to take a positive look at any such possibility on an individual proposal basis. Operating economies may be anticipated not only through improved control and efficiency fo the thermal cycle, but there may also be advantageous volu[illegible] discounts in the purchase of supplies and equip[illegible] resulting from Ontario Hydro's participation in such a scheme.

It might be of value to review some very interesting installations of this kind in other utilities w[illegible] emphasis on the rates used. One of Canada's major p[illegible] venture cogeneration facilities is located in Albe[illegible] and operated by AEC Power Ltd. which is jointly ow[illegible]ed by Alberta Energy Co. (2/3) and Calgary Power L[illegible]

(1/3). AEC Power Ltd. basically manages the syncrude utilities whereby the whole system is tied into the Alberta grid through Alberta Power Ltd. AEC Power Ltd. balances its load with the Alberta grid on an hourly basis, with the tie-in necessitated by four large syncrude draglines, each of which draws approximately 8 MW on a swing. A coincident swing by two or more shovels may require a draw from the grid, but this is partially off-set through their braking action.

In any event, this is a unique venture with the single captive customer being Syncrude. AEC Power Ltd. does not have a specific electrical power, steam or process water rate; rather, it operates on a full cost of service basis with the fair rate of return being subject to arbitration if a mutual settlement cannot otherwise be reached.

I would like to comment on another co-generation facility located in Nova Scotia. It involves the Nova Scotia Power Corporation project located at Point Tupper known as Tupper One. The NSPC has a special contract with Atomic Energy of Canada (AECL) to supply it with steam heat and electric power. The NSPC-AECL Agreement is unique because the parties are inter-dependent; one supplies steam and power while the other supplies condensation and boiler feedwater. If the NSPC Tupper One is freed from the AECL load, it cannot operate, and there is no product to sell. Even though the utility's investment is not located on-site, we have a type of joint venture through reason of their inter-dependence.

To accommodate this venture, a combined steam and power rate was designed based on service from a topping turbine. The rate is based upon the relative quantities of power and energy available to the customer and to the NSPC for general system use, and is derived from a general formula designed to supply to more than one customer if so required. Because of the complexity of the rate formula, I cannot take the time to go into its detail now. For those specifically interested, the combined steam and power rate is contained in the NSPC schedule of rates approved by the Nova Scotia Commission.

Nova Scotia has yet another interesting case involving the NSPC at Glace Bay. Here, the NSPC produces both steam for AECL and electricity for general use. Since 1972, the charge for steam has been based on the **incremental** cost of service. There is no physical asset separation and the condensate is not returned. However, this matter was recently brought before the Nova Scotia Public Utilities Commission where it was **alleged** that the electrical customers have been cross-subsidizing the steam customers and that a more appropriate method of determining the cost for steam should be based on a **fully distributed** cost study. Based on the findings of the commission, apparently the incremental approach has been abandoned in favour of the traditional fully distributed cost separation basically because the provision of steam heretofore considered a type of residual barnacle is now considered the basic raison d'etre of this utility. On this basis, the method of determining the cost of steam will parallel that method used by the corporation to determine its other rates. It is noteworthy that the incremental approach, in place for some six years, has been challenged as unconscienable in a public utility operation.

In the U.S. one of the more interesting cogeneration projects is the Eugene Water and Electric Board's joint venture with the Weyerhauser Co. in Oregon. The plant features a 51 MW steam turbine generator owned by the utility at the paper mill site and three boilers owned and operated by the paper company and fueled by oil, gas and mill product.

The overall efficiency is 81% and electrical generation costs 18 mills per KWH. The utility does not require the power until the mid 80's and is wheeling the power south to Los Angeles in the interim.

In order to determine the rate, a detailed engineering analysis was made to determine the additional fuel firing rate required for the energy extracted from the steam at full load. Based on this firing rate and using a typical 400,000 LB/HR oil/gas boiler, a value was determined for that portion of the boiler capacity dedicated to the turbine generator. Using industry's return on invested capital, a rate was established that is based upon the KWH actually produced.

By using this method, industry has an incentive to maximize the KWH produced and, conversely, the utility only pays for that portion of the boiler capacity that is actually used. This is important since the utility does not control the process steam requirements which determine the electrical production. The rate per KWH is constant over the life of the contract.

In addition, there is a penalty payment if steam is not available for more than 60 days annually.

Another example in the U.S. is the Southwestern Public Service Co. in Texas. This utility has three joint venture projects in the state where in each case it owns the turbines. In the one instance, the customer pays the standard rate for any electricity it uses, thus eliminating a separate charge for standby power. In exchange, this customer derives its benefit through a discount on the gas consumed by the turbine. It is also interesting to note that apparently each of these customers has a clause rendering the joint venture scheme void should the regulatory authorities attempt to define these customers as a utility subject to rate regulation.

Having commented on the subject from three different perspectives in an attempt to more adequately describe the circumstances unique to each, I would now like to make a few remarks on the subject as a whole.

For example, what does the future hold? Perhaps it would be unfair to quote specific numbers; nevertheless, the impact of future changes can be reviewed briefly. Currently, the industrial rates are generally based on historical average costs; however, as many of you are probably quite well aware, Ontario Hydro is currently involved in a costing and pricing hearing before the Ontario Energy Board, the thrust of which is to review Ontario Hydro's existing rate structure

and to consider the possible movement to rates which more closely reflect its marginal costs. It would be inappropriate for me to speculate as to the outcome of this matter inasmuch as the hearing is still in progress.

In any event, if some movement to marginal cost based rates was found to be appropriate and in addition if marginal cost based rates were determined to be greater than historical average cost based rates, then I think it would be clear that the threshold level would move in the direction of making cogeneration more attractive.

On this note, apparently California's movement to an inverted rate structure has generated some ripples. With an increase in the electrical rates to the larger volume customers, primarily being the industrials with high load factors, there may be an adverse short-term effect if industry's impetus toward cogeneration puts an undue burden on the existing utility revenues. The utilities perhaps should include in their calculations the expected loss in revenue from reduced sales of electricity to those industrial customers who will no longer require a continuous supply.

G. H. Lovin of the Edison Electric Institute and also chairman of the board of the newly formed International Cogeneration Society said "today there are more questions connected with cogeneration than there are answers." Included in his list of unkowns are synchronization of the cogeneration system with the utility grid, freedom from regulation and the appropriate **rate structure.**

There are indeed many factors to be considered when attempting to arrive at a reasonable rate to cover the forenoted options. Some **positive** cost based factors which may enhance cogeneration include:

(A) Increasing electrical rates
(B) Levelling of additional economies of scale in the utility
(C) Costly environmental compliance to the utility
(D) Costly regulatory approvals
(E) Costly siting squabbles
(F) Reduced capital investment by the utility, and
(G) Reduction of line-losses with on-site generation.

However, on the other side of the [illegible] there may be some **negative** factors associated with [illegible] if it is pursued without adequate [illegible]. For example, there may be a loss of [illegible] resulting in higher rates in [illegible] creased dependence on sm[illegible] This may prompt requirem[illegible] reserves. There may also be [illegible] ment problems caused [illegible] of purchased and whe[illegible]

It is not my inten[illegible] discouraging note, for the contin[illegible] tricity and fuel prices along with [illegible] on conservation and the more [illegible] energy makes it increasin[illegible] economics of self-ge[illegible]

Further, [illegible] factors, we should [illegible] volved. On a relati[illegible] faced cogenerating facilitie[illegible] ly 800 MW compared to [illegible] ty of about 20,000 MW. [illegible] the apparently negative fa[illegible] not stand in the way of progr[illegible]

Let me conclude by assuring you [illegible] is becoming increasingly cognizant [illegible] parent obstacles which must be reso[illegible] drafting of firm policies, goals and s[illegible] relating to cogeneration. And in the [illegible] dress to you today, the appro[illegible] policies on standby charges [illegible] price and terms at which [illegible] surplus power, and the imp[illegible] rate structures, including time-of [illegible] reviewed in conjunction [illegible] facets of cogeneration feasibilit[illegible]

Discussion:

Rates and Rate Structure for Industrial Cogeneration Installations

H. C. PALMER

Manager Rates, Ontario Hydro

Question: Mr. McCullum, *Westinghouse*

On the subject of capacity payments for power sold to Ontario Hydro, you have made some comments, and recognizing the investment in generation capacity in Ontario Hydro is really set by demands in the cold weather period - (that sets the magnitude of investment, that's when the peaks occur,) and neglecting for the moment that Ontario H[illegible] very large margin of surplus capa[illegible] reasonable to expect that Hydro [illegible] some place for (you said 250 day [illegible] loading), but would they recognize som[illegible] payment of capacity charges to a cog[illegible] ducer who could reasonably pr[illegible]

mand capacity and kilowatt hour production during the winter months. In other words, I'm back again to what I've encountered for years and years, as users of electricity have come to us and asked about quotations for steam turbine plants and gas turbine plants. In the winter we have this problem of gas turbine generators having considerable extra capacity, topping steam turbines have extra capacity because of the increase in steam flow for climatic factors, so here in the winter again is this seasonal surplus of power coming, it seems to me, at a time when Ontario Hydro could use it and if they could see it as reasonably reliable, they would grant some place in the pricing of the power for capacity, rather than just incremental cost to the producer. Is that a reasonable thing to expect of Hydro?

Answer: Mr. Palmer

Yes, I think it is. In the long-term if the customer, the cogenerator wants to make a commitment to the Ontario Hydro to provide generation during the peak months, the winter months, that generation in the long term will be valuable. It's much more valuable in that period than it is say in the spring and fall months.

Question: Mr. McCallum

Just as a supplement it seems to me the issue or the question is even magnified if you are prepared to grant any degree of success to the idea of cogeneration in Ontario. What this amounts to is taking away the high-load factor customers of Ontario Hydro and magnifying the peaking problem in the winter. Therefore, it helps solve the problem it creates.

If you go through these studies of cogeneration, you're going to find, or at least we find, that the most attractive economics occur when there is a very high load factor. A 5,000 kilowatt steam TG set works at 5,000kilowatts, 8760 hours of the year or thereabouts, and if this load is removed from Ontario Hydro 500 times over or some significant number, what it means is, on the time/demand curve of Ontario Hydro, you're just cutting a layer right off the bottom and increasing the peaking, or the ratio of peak, to generation in the whole system. Therefore, given time to work off the surplus of capacity, then, I may be exaggerating the potential of all this, but the end result will be to have a situation where the demand on Ontario Hydro in the winter, from all the other industries that don't have cogeneration, and from the residential and commercial demands, will be much more significant in its operations. Therefore, being able to buy back seasonably available power from a cogeneration producer in the wintertime should be even more and more attractive.

Answer: Mr. Palmer

I agree with you.

Question: Mr. G. McGorman, *Algoma Steel Corporation Ltd.*

What would Hydro's attitude be to a situation like this? Imagine a 25 megawatt machine, normally driven by an inplant steam system, steam turbine, which if equipped with a dual-drive, could be switched to electric power during plant off-peak periods which might conceivably not coincide with system-peak periods. Would you be happy with a thing like that or not?

Answer: Mr. Palmer

Probably not too happy.

Question: Ken Voss, *Ontario Paper*

I think part of this discussion is pretty irrelevant because isn't it so that the majority of the peak demand comes from the commercial and residential sector other than the industrial, which is a pretty high load factor and therefore not contributing so much to the peaking problems.

Mr. Palmer:

If I may interrupt you before you go on. The peak demand is caused by those customers who are on the system at the time the peak demand is created.

Mr. Voss:

Yes. This is an argument that I don't wish to pursue at this point, but I'd like to know the rationale for Hydro's charging for stand-by power on a capacity basis, especially in the times of exceeding reserve capacity. For instance, Dr. Drinkwalter's projections this morning looked for 800 megs of cogeneration. at 65 cents a kilowatt month, this brings Hydro a revenue of $6 million a year, and I just don't see the justification for that type of revenue for stand-by facilities.

Answer: Mr. Palmer

Well, allow me first to say that the calculation on which the stand-by charge is based, has no component in it for generation. It has not been included. The only components that are in it are those components that make up the standard charge in addition to generation itself, and they have been reduced by the order of 80 or 85% to make up the stand-by charge. Because there are costs connected with providing the stand-by service, I guess it's the only justification. I don't have the details with me as to how the individual components are charged. It isn't on the total local generation either. It's just on either 10% or on the largest unit.

Question: Mr. George Weldon, *Union Carbide Canada Ltd.*

One area you did not touch on, other than in the introductory section of your talk, was the question of power wheeling. I was wondering if you're willing to mention anything about the rate aspects of wheeling power through the Hydro system.

Answer: Mr. Palmer

We do have two cases on the system of wheeling at the moment, and those have been worked out individually, taking into account what it actually costs Ontario Hydro to wheel the power from between the two locations, and we are open to other situations where people want to wheel power and at the moment, we'll look at them sort of one-by-one. There is one question in the matter that came up during that discussion that interested me, and that

is this. All the municipal utilities in Ontario Hydro can, if they wish, generate their own electricity. They are not required to buy it from the Ontario Hydro; there is nothing in our Act or in the municipal Acts to prevent them, and in fact, there are a good many utilities, I can't tell you exactly how many, who do generate their own electricity. It also seems to me that there is nothing that would prevent an industrial customer in the utility from making arrangements at the local utility with the sale of surplus generation.

Question: Mr. Roger, *Reed Paper Co.*

While it was quite interesting to hear you talk about the problems of standby power for windmills and solar power, I kind of agree with Bill Twaits who said; look fellows, that's a little ways out there. On the other hand, it seems to me we are left with

Federal Government's Policy Regarding Cogeneration

DR. IAN E. EFFORD,
Energy Mines & Resources, Ottawa

I want to emphasize that I'm going to talk about the national perspective, and not specifically the Ontario view, and I'm going to talk about the policy aspects and the policy perspectives rather than the technical aspects.

The central issue I think in cogeneration is its relationship to the idea that energy saved is energy produced. The point that I'm particularly concerned with is cogeneration in the context of using waste material, or obviously of using energy a lot more efficiently. The essential component I think is that cogeneration is a form of the use of energy which is economically very reasonable, particularly if it can be done at costs that are a lot less than supplies of other forms of fuel.

The emphasis that we have in looking at cogeneration I think is in two forms. The first form is: what can we do from the R&D end, the areas where we have considerable responsibility within the system, and what can we do in viewing the problem from other aspects, for example, the financial aspects.

From the R&D end, we've made a number of commitments which can be related to trying to remove the technical problems with regard to cogeneration. Generally, it's viewed that the technical problems are not in the electrical generation end, but in the processing of waste end, and we have begun by trying to define what the potential is for both a potential for cogeneration within industry (doing that in association with the IEA study which is going on across all of the IEA countries,) and also looking at some of the more advanced technical potential for new methods of using energy in cogeneration systems. Therefore we have sort of a background study looking at the potential within Canadian industry, and there are complimentary studies looking at some of the potentials for the production of waste material and the energy that is available in that waste to use in cogeneration. We have also had some studies done on the potential for the need for low temperature energy, and of course the normal figure given is that about 50% of our energy need is low temperature energy, and these are well satisfied by the byproducts of cogenerating facilities.

From that sort of over view study we go into the more specific, and we have funded a series of studies which are designed to look at the front end burning or gasification processes which are available. These are meant to be R&D studies which either test a particular type of facility to see whether it should be expanded to the pilot stage, or alternatively, test a pilot plant stage system to see whether it, in fact, can be taken further into an economically viable system. I will mention a few of these to illustrate the range of studies which have been funded either on a special grant or, in fact, a wide range of granting systems from the R&D panel, or as particular individual studies.

We are studying some tests, with Saskatchewan Power Corporation, using an embered gasifier. This is a study of a 20 kW gasifier using farm and forest waste, which is used for grain drying and heating and power generation. One of the studies is to try to move to a commerical stage with that gasifier as far as providing energy for kiln drying, generation of electricity and for space heating. This is using saw mill waste to produce low BTU gas.

In the northern part of New Brunswick we have a program to try and look into the feasibility for a 50 MW peatified steam generation plant, if not quite using waste, but certainly with the hope that the plant would be easily adaptable to using organic [illegible] similar to peat. In a slightly different phase, in Prince Edward Island we will be supporting the construction of a plant which will be burning a mixture of garbage

and wood waste, where the wood is used to balance the fluxuations in the garbage, so that the daily, weekly or seasonable fluxuations in the garbage are leveled off with wood, and the attempt is to build a system which can burn the two and manage the burning of the two fairly efficiently.

Also in PEI we have in the D&D station at Summerside a program to build an atmospheric fludized bed combustor for burning coal and wood, up to 30% wood in that case, to supply steam to the plant, and the system would be able to operate with a cogeneration facility if it is desired.

Then, going through to the use of municipal garbage in a different form, we have just agreed to fund the study of cogeneration in Montreal, using the downtown garbage for district heating within the central part of Montreal.

Likewise there are funds going into the Canadian Electrical Association (CEA) project to look at the more integrated system at Point Tupper. All of these studies are intended to provide the cost of testing the R&D or the implimentation of particular forms of cogeneration facilities.

Furthermore, we have provided for funds through the new federal-provincial agreements, money at the level of 114 million to be used in seven of the provinces and the two territories to fund similar types of studies, although not necessarily in cogeneration, — yet we think some of the provinces will propose cogeneration type tests. These funds compliment other funds which are available in the remaining provinces so that now in all provinces there are programs for R&D funding for demonstrations of new types of renewable or conservation technologies. Those funds are not intended to pay for the whole cost of a particular plant, but they are usually designed to pay for the difference in costs between, for example, an oil fired plant and a new type of plant which may use garbage and wood. The difference in cost is intended to be the amount picked up by those grants, and I can well imagine that we will cover quite a few different types of tests right across the province proposed from the provinces.

Those funds are all designed to look at the problem of R&D and particularly the demonstration aspects. Frequently we get into the point where many of these programs are through the "R" and the preliminary of the "D" but not into the actual demonstration in a practical way, and that's what the money is provided for.

I should mention that those funds are to be administered through the provinces, so that we would expect the provinces to be recommending what should be funded, rather than the federal government.

That covers one aspect of the work that the federal government is doing in co-generation. The other aspect is the problem we see in the financial end. Obviously, we see a considerable need, because of the high cost of energy in the future, to pick up more cogeneration based on waste material. If you have forest waste being produced at about the same rate that coal is mined in this country, there is a very significant potential to generate energy from that waste. It should be generated at lower cost, one would hope, than mining and moving coal, or possibly exploring and producing oil in the Artic and so on.

The problem we see then is why don't we go ahead? I think one of the reasons we don't go ahead with cogeneration is the perspective on cogeneration at the different levels. I would like to just touch on that for a minute.

If we have a cogeneration facility, and we've had some detailed discussions today already on the return on investment, the usual perspective is taken by the company. The company finds that it has a lot of wood waste. It could use that wood waste to generate electricity and to use the steam in its plant. It looks at the return on investment and discovers it at 15-16% let's say.

The first thing we have is the problem of capital shortage within companies at the present time so they don't want to proceed, and when they do have money they look at other investments, and they may find that other investments are at least double that return on investment, and so they use the money elsewhere. That is one problem. However, at the same time, that return on investment may be higher than the perspective of the local utility, (the return it needs on investment to generate electricity,) and it may be higher than the total cost of the country of going out and finding an equivalent amount of oil at the margin in the Beaufort Sea. So this is one of the problems that we are up against. One is capital shortage, the second one is perspective, the third one, as we see it, are institutional problems which have been touched on in the last speech.

There is certainly a wide range of cogeneration potential across the country, and some companies are going to pick that up and go ahead and, in fact, invest their money. We know of some. One of them recently was talking to us which is going to back out 400,000 barrels of oil a year from one particular facility. That is a very major saving in terms of the national effort. Other companies will not go ahead. Such delays, I think, have an overall impact on out total energy policy and on our energy efficiency. It's unfortunate that we have this sort of problem. The federal government does have some programs which are designed to try to remove this sort of issue. One of them as I mentioned will be the funding of some of these projects, probably through the federal provincial agreements. The second one is through the fire program which was announced last summer. We are providing 20% grants to facilities which use wood waste for industrial waste to back out primary energy forms like oil.

These particular programs are not designed to pay for the cogeneration facilities themselves, but are designed to pay for the front end part of the work - ie: the burning and the boiler part of the program. Hopefully, by providing that additional capital, they will stimulate the company to look more favourably at going through to completion of the whole project.

It was mentioned by one of the other speakers that we have the class 34 capital tax allowance which specifically applies to the cogeneration facilities themselves.

Last summer the loan agreement program was also announced. It is designed to guarantee the loans of facilities which either burn wood waste or other waste to generate energy - 50% of the loan will be guaranteed. To cogenerate electricity with other forms of heat energy, 66-2/3% of the loan will be guaranteed. That program becomes effective on April 1, and we would be guaranteeing a loan of a new plant in most of the provinces and possibly, if they were quite different plants, more than one in a province.

Finally, on the East Coast, in PEI and Nova Scotia, we do have programs which are designed to help industry increase their efficiency by changing the plant structure grant program. In those cases, obviously cogeneration facilities would be considered very seriously.

In conclusion, I would like to say that firstly, it is obvious that programs won't remove the financial barriers to cogeneration. I don't think it can be done by any one organization within the system. It can be done hopefully by all of the organizations working together. I think the suggestion that the utility should be involved in joint projects is a very good one. They have much greater ability to obtain capital for this sort of thing than many of the companies do. Joint ventures themselves were mentioned. They already take place in at least three of the provinces. Hopefully, these could be expanded both within those provinces and to other provinces across the country.

I was going to say a few words about district heating, but I will leave that for now and just say that in terms of the overall perspective on energy conservation, the Canadian industry in fact is doing very well. It has set a voluntary target for 1980 of a saving of 12% over earlier consumption. (Between 1962 and 1972, the gross rate was around 4.9% and has declined between 1972 and now to 3.5%.) If we maintain the voluntary target of 12% in 1980, and if we can add an additional 10-13% saving from 1980 to 1990, which we don't think is unreasonable, then we would expect an overall industrial growth rate in energy consumption of only around 2.2% or just above that.

By 1980 such a growth rate change means a saving of 150 million barrels of oil a year, or about $2 billion dollars to Canadian industry. It makes it a lot more competitive and more efficient.

At the same time, a real thrust in developing cogeneration to use waste, whether it is wood waste, industrial waste, or municipal waste, would add to that change in efficiency, would increase the efficiency and cut the overall cost down quite considerably. I think in the process of doing that, it would make us very much more competitive, and it would cut down the cost to the nation of looking for and producing new energy whether it is oil energy, gas energy or even electrical energy. Thank you.

Discussion:

The Federal Government's Policy Regarding Cogeneration

DR. IAN EFFORD, *Department of Energy, Mines and Resources, Ottawa*

Question: Gordon Robb, *Energy, Mines & Resources*

I just wanted to elaborate a little about what Ian said about Class 34. There seems to be some confusion about that. That's a special class for cogeneration and it applies, if you are installing a turbine generator, to the entire boiler turbine and quite a bit more. The boilers have been getting a two year write-up under Class 29, but there was an exclusion of turbine generators so 34 was put in specifically to give a straight line two year write-off for turbine generators, and to get that you talk to the Department of Industry, Trade and Commerce who administer that program. I believe Dr. Drinkwalter mentioned his studies were based on 25%, the two year write-off would be 50% CCA.

Question: George Weldon, *Union Carbide*

Ian, I was wondering if your department was doing any studies to identify the synergisms that might result from the clustering of industries and whether or not there is real potential for that anywhere in the near future time frame?

Answer: Dr. Efford

That is part of the IEA study on cogeneration potential in the various IEA countries, and it would be part of the study in Canada, and certainly it is something that we feel should be examined in considerable detail because it is one of the strengths of a number of the European industrial complexes that they cut their energy demand down by forming a network and feeding it around and around, so that everbody uses it, whenever they need it, and they use it most efficiently.

Cost of Production of Electricity with Wood By-Products "Hearst Study"

Panel Discussion by:
R. L. GUDGEON,
Acres Shawinigan
A. ROGERS,
Ontario Hydro
R. M. R. HIGGIN,
Ontario Ministry of Energy

The investigation of hog fuel surplus in the Hearst area of Northern Ontario showed an average yearly surplus of 300 tons per day at the present rate of saw mill production. Based on this quantity of bark, saw dust etc., a preliminary plant design was completed which utilized this fuel for the generation of electrical power. Capital and electrical-generation costs were developed from the preliminary plant design based on electrical output, steam conditions, kiln-heating option, financial criteria, fuel costs etc.

Prepared Notes for Discussion by:

R. L. GUDGEON,
Acres Shawinigan

Part I - Technical and Economic Evaluation

The Hearst Study was motivated originally by problems arising in the disposal of wood wastes from the lumber mills in the Hearst area. The traditional methods of disposal had been by landfill or burning in "teepee" burners, both coming under the scrutiny of the Ontario Ministry of Environment.

Burning the wastes alone produces a smoke which contains a high proportion of unburnt carbon particulates. These particulates are deposited from the atmosphere on to the surrounding country and communities in quantities which were beyond limits acceptable to the Ministry. To reduce this emission to acceptable levels, the Ministry stipulated the addition of oil burners and controlled air supply to the teepee burners to improve combustion conditions and reduce the amount of particulate carryover.

The oil burners with their associated oil storage tanks are costly to install. Also the annual cost of the fuel oil would be significant and without any compensation from recovery of the heat supplied by the oil. Hence, the local lumber mills, under the auspices of the Hearst Lumberman's Association and the Town of Hearst, proposed a study of the use of the wood wastes to produce steam and power; the steam to dry lumber and provide district heating, the power fed into the Hearst PUC system. Garbage from the Hearst area would also be considered as a supplementary fuel.

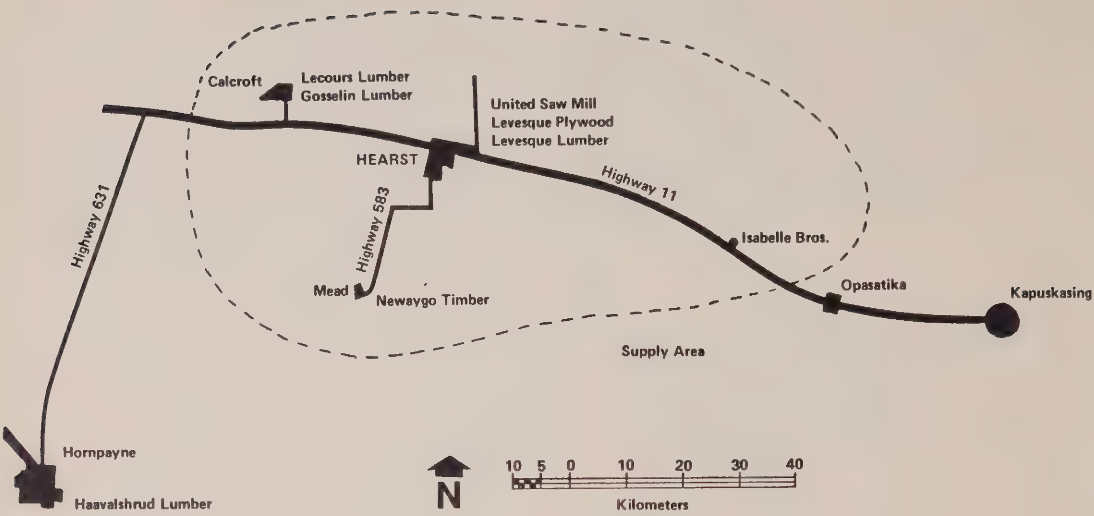
Accordingly, in 1976, SNC Consultants [illegible] conceptual study on the use of the wood [illegible] source of energy. Their study covered [illegible] of extracting this energy, including gasif[illegible] cluded that a steam/power plant in [illegible] shown to be technically and economi[illegible] recommended further detail study. [illegible] Shawinigan were commissioned [illegible] liminary design and carry out [illegible] of a wood waste fired steam [illegible]

The study was [illegible] Ministry of the Environment [illegible] established following the [illegible] Ontario Cabinet by the [illegible] tion and the Town of [illegible] mittee were the [illegible] Energy and Natural [illegible] Association and the [illegible] committee was [illegible] dustry and Tourism [illegible] Hydro, and the Northern [illegible] poration.

The most important parameter [illegible] amount of wood wastes available [illegible] reliability of this availability [illegible] wood waste supply area is shown in Graph [illegible] first survey indicated an annual quantity of [illegible] ODT (oven dried tons). Burning this wood on a [illegible] basis for 8,000 hours per year would permit the [illegible] tion of up to 19 MW in a steam turbine pow[illegible] without process steam extraction and up [illegible] when extracting 42,000 pounds per hour [illegible] in a Hearst plywood mill. A high load [illegible] assumed to reduce the energy costs at[illegible] capital repayment to a minimum. Subseq[illegible] suggested less quantities of wood wastes [illegible]

HEARST WOOD WASTE ENERGY COMPLEX
WOOD WASTE SUPPLY AREA

GRAPH 1



HEARST ENERGY COMPLEX STUDY
TABLE 1
SUMMARY OF SCHEMES INVESTIGATED

Alternative	Fuel Quantity ODT Wood Residue/Year (Plus 20T/Day Municipal Refuse)	Steam Sold	No Steam Sold	Electricity Sold To: Ontario Hydro	Hearst PUC
a) 1	159,000	Yes		Yes	
a) 2	159,000	Yes		Yes	Yes
a) 3	159,000		Yes	Yes	
a) 4	159,000		Yes	Yes	Yes
b) 5	137,000 + 22,000	Yes		Yes	
b) 6	137,000 + 22,000	Yes		Yes	Yes
b) 7	137,000 + 22,000		Yes	Yes	
b) 8	137,000 + 22,000		Yes	Yes	Yes
c) 9	137,000	Yes		Yes	
c) 10	137,000	Yes		Yes	Yes
c) 11	137,000		Yes	Yes	
c) 12	137,000		Yes	Yes	Yes
d) 13	137,000	Yes		Yes	
d) 14	137,000		Yes	Yes	
e) 15	137,000	Yes		Yes	
e) 16	137,000		Yes	Yes	

a) Base case
b) 22,000 ODT of slash to be collected from the bush and delivered to the Complex at cost.
c) Complex size based on lower quantity of wood residue available.
d) Complex size considered same as in Alternative a).
Operating mode considers a shutdown period in the summer to compensate for the lower amount of wood residue available per year.
e) Complex size considered same as in Alternative a). Operating mode considers reduced load during night periods (10:00 pm to 6:00 am) year round.

available, down to 137,000 tons per year, with a correspondingly lower power generation capacity.

Other parameters included the credit that would be given by the Hearst PUC and Ontario Hydro for the electric energy generated. Ontario Hydro would pay for the plant capacity in constant dollars each year, reflecting their option to construct a similar capacity plant in the same year and, thereby, fix the capital cost. The Hearst PUC would pay for the capacity, in current dollars, on a year-to-year basis. This advantage, however, would be offset partly by a standby capacity charge from Hydro and partly by the lower rate paid by the PUC for energy. Consideration was given to variable plant loading whereby generation would be increased during the day and decreased at night to take advantage of the higher credit available during peak hours. Operation with and without process steam extraction was also examined.

Sixteen schemes based on combinations of the above four parameters, wood quantity, energy credit, load characteristic and steam extraction, were investigated. They are summarized in Table I. Annual cash flows, both escalated and unescalated, were developed for each scheme and the internal rate of return calculated.

The cash flows started at inception of the project and extended to the end of its economic life. They included, initially, the direct project costs, engineering and administration, interest during construction, and an allowance for contingencies. The ongoing annual costs included the cost of the fuel, wood waste, operating labour, maintenance, operating supply and capital repayment. On the revenue side were the incomes from the sale of electric energy and steam.

The results of the rate of return calculations are summarized in Table 2. It can be seen that the scheme having the highest rate of return was Scheme a)2. This scheme assumed 159,000 tons of wood waste would be burned per year, together with 20 tons of municipal garbage per day. Steam would be sold at an adjacent plywood mill at a rate of 48,000 pounds per hour. Electric capacity and energy would be sold to the Hearst PUC, any energy surplus to its requirements going to Ontario Hydro. In general, those schemes where steam is old and the energy is sold to the PUC show the highest rate of return whatever the quantity of wood burned.

HEARST ENERGY COMPLEX STUDY
TABLE 2
RATES OF RETURN

Alternative		Rate of Return Per Cent
a	1	9.2
	2	9.6
	3	7.3
	4	8.3
b	5	5.4
	6	6.5
	7	negative
	8	3.7
c	9	7.3
	10	7.5
	11	3.7
	12	5.0
d	13	7.0
	14	4.5
e	15	8.0
	16	5.1

The sensitivity of the rate of return to increases or decreases in various cost factors was tested for each scheme. The cost factors included capital cost, natural gas cost, steam and power revenues, operating labour cost, slash collection cost and standby power cost.

This first phase of the study concluded with the recommendation that a wood waste fired steam power plant be built in Hearst with a rated gross capacity of 22 MW (19 MW net). It would operate at 900 psig and 900 degrees F and the condenser pressure being two (2) inches Hg absolute. There would be a single boiler and a single turbine generator, probably with an air-cooled condenser. The estimated cost in 1977 dollars was $24,000,000.

The second phase of the study considered methods of financing the construction of the wood waste power plant. As part of this phase of the work, firmer commitments were sought from the Hearst lumbermen fo[illegible] the supply of the wood wastes in the longer term and from Ontario Hydro for the credit for energy. [illegible] process, one source, Haavalsvud Lumber [illegible] eliminated because of the cost of hauling the was[illegible] over some 80 miles. At the same time, one more mil[illegible] Isabelle Bros., was added.

The design annual wood waste quantity was [illegible]tually established as 129,000 ODT. The steam quantity to be extracted and sold was increased to 78,000 pounds per hour to accommodate kiln dryers at two mills in addition to the plywood mill. The recomm[illegible]ed power plant now had a rated gross capacit[illegible] MW and would have a total cost of $22,600,000 in 1978 dollars. The locations of the power plant and the mills to be supplied with steam are shown on Graph No. 2

A final summary report was issued to the Committee in October, 1978. It established the capital and operating costs of the smaller power plant and developed cash flows for two alternate approaches -selling energy to Ontario Hydro only and selling it [illegible] the Hearst PUC and Hydro.

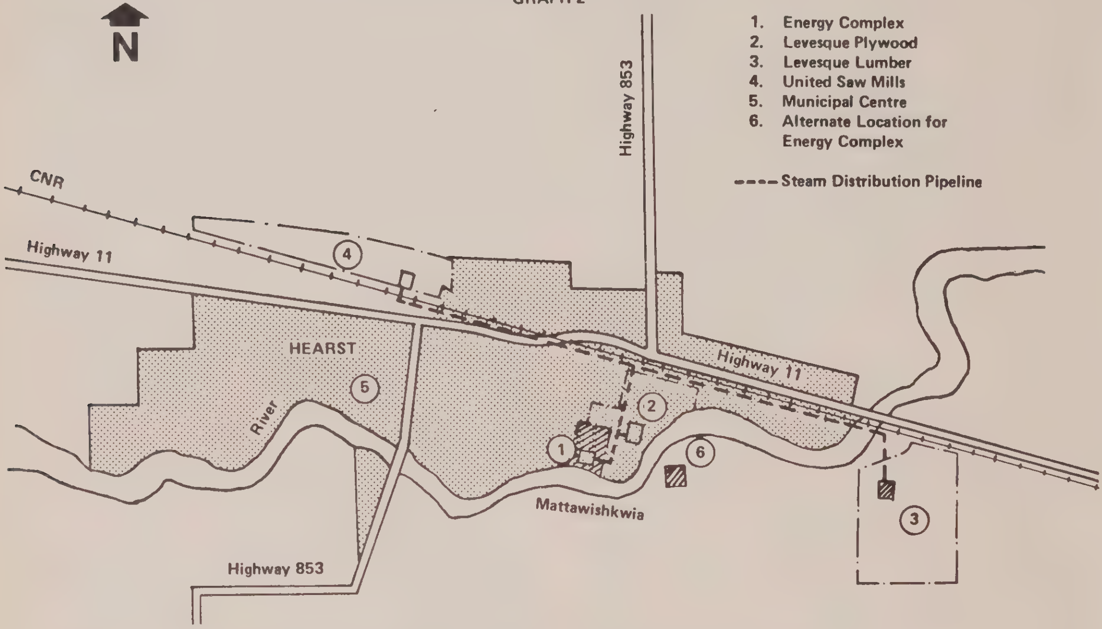
The plant would be supplied with wood wastes from seven mills within 40 km of Hearst. It would operate for 16 daytime hours at load equivalent to 137,000 ODT of waste per year and at 113,000 ODT for the remaining eight hours, the daily average load being equivalent to 129,000 ODT per year. The daytime net output would be 11.9 MW and nighttime 8.8 MW. The process steam load of 78,000 pounds per hour was assumed constant over 24 hours.

The internal rate of return based on inflated dollars was calculated to be 6.9 per cent if all energy was sold to Ontario Hydro and 8.5 per cent if sold to the PUC with surplus sold to Hydro. If the capital requireme[illegible] could be reduced by 20 per cent from contribution [illegible]

the various levels of government, these rates of return would be increased to 9.1 and 10.8 per cent respectively. The above rates of return are the average over an assumed 30-year plant life. The cash flow would be negative over the earlier years. The relation of income to expenditure for energy sales to Ontario Hydro -Alternative I and to the PUC - Alternative II, are shown on Graph No. 3.

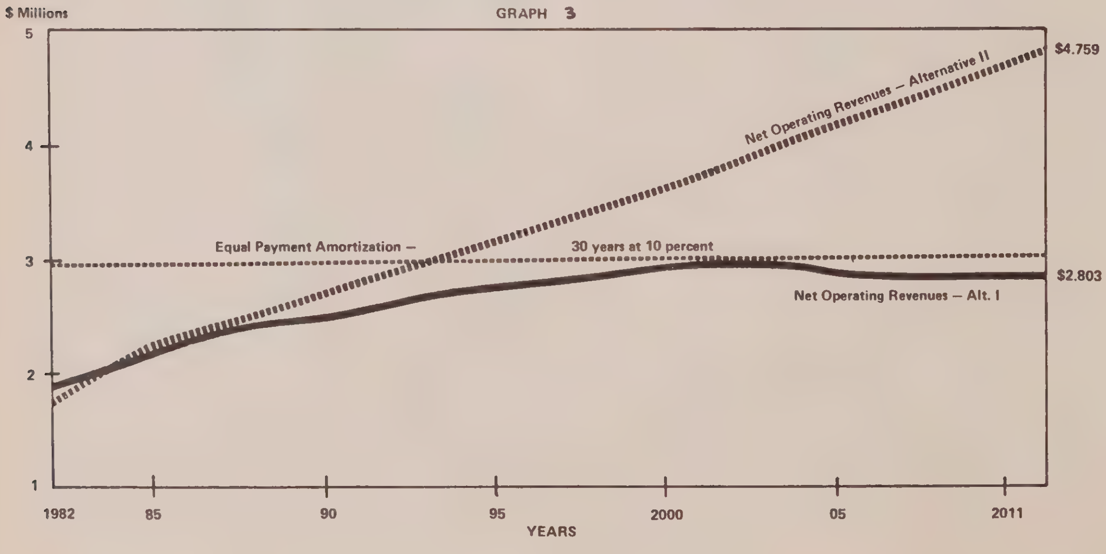
The summary report reviewed investment decision criteria and organizational alternatives. It set out points of negotiation that remained to be completed with firm agreements. These are between the power plant owner and the lumber companies, with regard to waste quantities and disposal cost, Ontario Hydro with regard to energy credits and the Town of Hearst with regard to plant location.

HEARST WOOD WASTE ENERGY COMPLEX
LOCATION PLAN
GRAPH 2



HEARST WOOD WASTE ENERGY COMPLEX
Net Operating Revenues (Escalated) for Revenue Alternatives I and II
and Illustration of Debt Repayment at 10% Over 30 Years

GRAPH 3



Prepared Notes for Discussion by:
A. W. ROGERS
Ontario Hydro

Hydro was pleased to play a part in the Hearst Wood Waste Study and to have an opportunity to contribute engineering and economic information in the power generation area.

The invitation to participate was a little unusual since it read "please send a delegate and bring money". This always makes us a little suspicious and more than a little cautious.

However, our main contribution was in that most important area of providing information on the value of capacity and energy so that potential revenues could be estimated and returns on investment determined over the 30 year project life.

We provided values for two basic alternatives which were:

1. Ontario Hydro buys all generation from the wood waste facility and continues to supply Hearst P.U.C. in the present manner.
2. Hearst P.U.C. purchase generation from the plant as required with Ontario Hydro purchasing the balance and providing standby capacity.

The estimated values we provided were based on certain key assumptions viz.

(a) An assumed high availability of 89%. We believe the reliability is high enough to justify the capacity credit that we proposed. However, we would want the ability under a contract to adjust this if the availability is significantly lower.*

(b) On the basis of the above high availability, a capacity credit was given using the cost of fossil generation in the year of implementation of $574/KW in 1981.
Using a load meeting capability of 92% (F.O.R. 8%), a Unit capacity of 11.9 MW, a 30 year amortization rate of 9.75% produced a constant dollar annual capacity allowance of $648,000.

(c) The energy credit is based on the value of incremental energy that would be displaced from the Ontario Hydro system over the period of the study. The values are derived mainly from fossil energy costs.

For the case where Hearst P.U.C. purchased energy directly from the waste wood plant, Hydro provided standby charges to cover this service plus wholesale bulk power rates made up of demand and energy charges and all are escalated using Hydro forecasts up to the year 1993 and applying 4.4% from 1994 onwards.

In the case where the Hearst P.U.C. purchases directly, the prices arrived at using the above bulk energy costs to the P.U.C. are higher than those

*Unit must be available at least 250 days per year, 16 hours per day, including peak load hours.

	Demand $/KW/Mon.	Energy Mills/Kwh.	Standby Charge $/KW/Year
1981	7.56	12.0	12.6
1982	8.19	13.0	13.56
1983	8.62	14.00	14.16
1984	9.17	14.9	15.07
1985	9.76	15.85	16.03
1986	10.38	16.86	17.06
1987	11.05	17.94	18.15
1988	11.75	19.09	19.31
1989	12.26	19.91	20.14
1990	12.78	20.77	21.00
1991	13.33	21.66	21.91
1992	13.91	22.59	22.85
1993	14.50	23.56	23.83

Beyond 1994 each rate is estimated to escalate 4.4% per annum.

Year	Mills/kWh		Year	Mills/kWh	
	Day	Night		Day	Night
1981	15.2	13.7	1996	39.2	21.36
1982	15.8	14.1	1997	41.25	20.93
1983	18.29	15.91	1998	43.41	20.39
1984	20.77	17.75	1999	45.67	19.72
1985	23.26	19.53	2000	48.06	18.92
1986	24.19	19.65	2001	50.16	17.99
1987	25.38	19.85	2002	52.33	16.9
1988	26.85	20.23	2003	54.60	15.63
1989	28.41	20.6	2004	56.95	14.17
1990	30.05	20.94	2005	59.40	12.49
1991	31.38	21.18	2006	61.94	13.11
1992	32.76	21.38	2007	64.58	13.77
1993	34.2	21.53	2008	67.33	14.46
1994	35.69	21.63	2009	70.18	15.18
1995	37.25	21.68	2010	73.13	15.94
			2011	75.64	16.74

calculated from the fossil capacity and energy displacement assumption and gave a better average rate of return of between 1.0 and 1.5 percent. This is due primarily to the capacity credit not being escalated in the latter case. Since the demand rate is escalated, it more truly represents a replacement capacity allowance in the current year. Ontario Hydro would be prepared in the Hearst case to use the bulk energy as a basis for contract negotiation.

Standby Power

Unless a user is prepared to risk the consequences of a power outage, Ontario Hydro is usually expected to provide standby or backup power.

Where a utility supplies more than one-third of its load from local generation other than Ontario Hydro, the standby charges are based on whichever is the greater of either:

1. 10% of the amount of power generated from the other sources or
2. the kilowatt rating of the largest unit

which is the case applying to the Hearst situation, and as an example, it could amount to approximately \$12.6/KW/annum x 11.9 MW = \$150,000. in the first year then escalating over the life of the plant.

Hydro Stance

Hydro does support and encourage facilities owned and operated by others whether it is private industry or a public utility. Where this is seen to be economic and attractive to someone, it must be a good thing for the province and it represents capacity that Hydro does not have to finance and build itself. However, where Hydro is relied upon for standby, then the standby insurance premium must be paid.

Public Utilities Act

Under the Public Utilities Act a municipal utility or P.U.C. may finance, own and operate its own generating facilities supplying power to its customers. So long as the project can be financed by the P.U.C. based on the merits of the project and using its own financing capability, then any rate advantage should be used at the discretion of the P.U.C. and for the benefit of its customers.

This would not be the case where the facilities must be financed by public funds.

Under the act, Ontario Hydro must approve the funds for such a project and the rates to be charged to the P.U.C. customers.

Organization for Undertaking the Project

The Ontario Hydro preference would be for the project to be owned and operated by others and, of course, if the project could be financed on its own economic merits, that would be the optimum situation.

Our present stance is a flexible one recognizing there are many items yet to be considered and some requiring negotiation.

We generally agree with the conclusions reached in the report and in particular that the project would:

1. Resolve an environmental and economic problem of wood waste disposal.
2. Use a valuable and renewable form of energy.

Of course there are many other social benefits which should be evaluated and perhaps quantified, if possible, as part of the study and the decision making process.

The critical items in the report as we see them are:

- Quantity and quality of wood waste available in the Hearst area.
- Logistics of supply continuity
- Value of wood waste over the long term i.e. disposal fee vs. market price
- Steam demand, load characteristics and value
- Value of the electrical energy produced
- Socio-economic factors
- Financing and organizational structure

In summary, Hydro has a strong interest in the project, and we intend to remain flexible and willing to consider any alternatives, in order to assist in achieving the best solution.

Prepared Notes for Discussion by:

R. M. R. HIGGIN,
P.h.D., P. Eng.
Ontario Ministry of Energy

Introduction

The background assumptions and technical design parameters of the Hearst Energy Complex have been well described by Bob Gudgeon of Acres Shawinigan and Al Rogers of Ontario Hydro.

Let us start on the right basis by indicating that Government became involved in Hearst because we were requested to assist the town and local industry to examine the cogeneration option.

Apart from anything else, you will have probably begun to realize that the Energy Complex is well named.

Because of the somewhat unique nature of this proposed co-operative cogeneration facility, the marginal economics which are extremely sensitive to steam and electricity revenues and the large number of participants, a decision by Government on whether to lend its support to the project is not a simple matter.

In the next few minutes, I will discuss a possible route to this decision and to the subsequent implementation of the facility, assuming the decision is favourable.

Review of Economic and Financial Position of Complex

The first task to be undertaken by all participants is a careful review of the technical parameters cost structure and revenue position of the proposed facility.

The critical factors are:

1. **Capital Cost of Cogeneration Plant**

   Based on similar industrial installations, a capital cost of $1600/kWe or $660/kWth could seem high. The consultants have carefully reviewed the figures and feel they are realistic. A similar facility in Burlington, Vermont is quoted at $1500/kWe in service 1980. Too often incorrect decisions are made on low capital costs so we are not out to reduce cost estimates arbitrarily.

2. **Steam Distribution and Plant Conversion Costs**

   The figures for steam distribution are probably as accurate as the other capital cost estimates. However, the inplant conversion costs have not been covered in detail and this matter, which ties in with the volume of steam, required steam conditions, and price of steam, must be further investigated.

3. **Annual Cost/Revenue Position**

   The unattractive economics of the base case and the marginal cash flow position of even the case with 20% grant, 20% equity are cause for concern. Revenues are very sensitive to the following factors:

   - steam sales (volume and price)
   - electrical sales - energy, demand/capacity credits and stand-by charges.

   A significant change in any one of these factors will adversely affect the revenue and cash flow position of the facility. There is currently concern that steam sales will only be 2/3 of that forecast.

The objective of the review is to obtain a better understanding of the critical points of negotiation and agreement and explore such items as:

level of risk, public/private participation, ownership and financing options, availability of loan guarantees, tax breaks, etc., contract terms and conditions needed.

The review will necessarily involve discussions with a wide range of public and private sector interests and will give a strong indication as to whether the facility is feasible and the extent of Governmental support required.

Review of All Alternatives to Current Situation Including Complex

In deciding whether to recommend Government of Ontario support for the Hearst facility, the Ministry would have to review once more the current situation in Hearst and the objectives which lead to the cogeneration proposal, and thoroughly assess all alternatives which can meet the objectives.

The *"Base Coat"* is continuation of current practises. Current methods of waste disposal are environmentally unacceptable and an ongoing cost to the industry. The installation of controlled air incinerators would be a financial burden to the industry and would result in higher per ton disposal costs. Resource values are lost and fossil energy must be consumed to dispose of the waste.

Alternatives to this situation must meet the primary objectives of environmentally acceptable disposal, stabilization of waste disposal costs and, hopefully, the production of useful energy. Secondary objectives are to demonstration alternative uses for wood waste especially the co-operative cogeneration concept, creation of local employment and increased local security of energy supply. Primary and secondary objectives may be met by the following:

1. Private sector waste utilization proposals, eg., prepared fuel (Woodex), industrial methanol, other?
2. Individual energy conversion facilities for each industry.
3. The cogeneration facility.
4. Primary objectives only may be met by trucking waste to another industrial co-generation facility or for other use.
5. Environmentally acceptable disposal objective only can be met by
   - new landfill site
   - incineration

From a government point of view, these alternatives are probably listed in decreasing order of attractiveness.

Feasibility and Cost/Benefit Analysis of Alternatives

The Government viewpoint will be to meet primary and secondary objectives with the maximum private and minimum public involvement.

Therefore, for each alternative, we will have to:

a) Define "costs" to government (at this point, a *range* is probably best).
b) Define benefits to Ontario.
c) Analyze the risks - technical, economic, and financial.
d) Determine the points of negotiation and agreement.

The likely conclusions of such an assessment are that private sector (or largely private sector) proposals are the preferred route, but the energy complex could proceed if satisfactory arrangements can be reached among participants.

The fallback position is for the companies to install their own energy conversion facilities and/or adopt envrionmentally acceptable waste disposal practices.

Agreement and Approval Stage

Assuming that a project such as the Hearst Energy Complex is to proceed with public sector participation and that the Government agencies concerned have agreed in principal to support the project, the next step will be to develop an interim agreement among public

and private sector interests who have a citical involvement in the success of the enterprise.

A number of critical items of agreement have already been identified and others will arise through the review and assessment stages.

Disposal Fees	• Long-term debt
Steam Sales	• Equity position of lumber companies
Waste Supply	• Ownership structure
Allowable Timber Cut	• Operational Management

Agreement must, at this point, contain criteria which will allow withdrawal should costs overrun or unforeseen circumstances worsen the financial picture of the facility. The agreement would also indicate the preferred route to implementation, either private or public.

The signatories to such an agreement would include, at least, the Lumbermen, the Town of Hearst and Hearst Public Utilities Commission, Ontario Hydro, the Federal and Provincial Governments.

Implementation of the Energy Complex

The route preferred by the Ministry of Energy would be one in which private sector participation is sought on the financing, construction, ownership, and operation of the facility.

To obtain firm proposals of private sector interest, it will be necessary as a **minimum** to develop a design brief outlining the main technical and economical parameters and to obtain the necessary site and environmental approvals. In addition, the availability of Government grants, guarantees and tax write-offs will need to be detailed.

As a fallback, the project could proceed to final design and construction as a totally public sector project.

Summary and Postscript

As participants at this cogeneration seminar, you are now aware that the economics of a cogeneration facility in Hearst are marginal and that, reaching a point at which the facility could be committed, would require a period of protracted negotiation, and a substantial amount of "give" by all participants.

It is probably hard to disagree with the primary and secondary objectives for the Hearst project. The question is at what point should we be taking action to make such a facility a visible reality? Maybe it is still too premature - a concept whose time has yet to come.

At the moment, the situation is that private sector interests are considering the construction of a prepared fuel plant in Hearst. This will meet all of the primary and secondary objectives perhaps at zero cost to the Ontario taxpayer. We hope it will become a reality because, the cogeneration facility when considered further may still be prone to be an idea before its time.

I hope that those of you representing private sectors interests will communicate your feelings about a cooperative cogeneration facility such as Hearst, to the Ministry of Energy if you have a positive contribution to make to the issues outlined today.

HEARST - STEPS IN DECISION AND IMPLEMENTATION PROCESS

- **REVIEW ECONOMIC AND FINANCIAL POSITION OF COMPLEX**
- **REVIEW ALTERNATIVES TO COMPLEX**
- **COST-BENEFIT ANALYSIS OF COMPLEX Vs ALTERNATIVES**
- **APPROVALS AND AGREEMENTS**
- **IMPLEMENTATION**

Hearst Cogeneration Study Summary

Technical Parameters

Design Capacity	137,000 odt/yr
Steam Output	166,000 lb/hr
Turbine	14 mw gross
Plant Capacity Factor	82%
LP Steam	78,000 lb/hr continuous
Electricity	84.5 million kwh/yr

Economic Parameters ($1978 MILLION)

Basic Capital Cost	$15.5
Design Management Profit Ect.	$ 5.43
IDC	$ 1.66
TOTAL	$22.6 ($660/KW)
Annual Costs $1978	
Wood, O & M	$1.43 (excluding debt service)
Revenues	$ 2.68

Financing Structures

Base Case: 100% Debt 30 Years
Total to be financed $27.8 million
Illustration 3: 20% grant ($5.6 million) + 80% debt
Illustration 5:20% grant + 20% non preferred equity + 60% debt

Discussion:

The cost of Production of Electricity with Wood By-Products — "Hearst Study"

R. L. Gudgeon, *Acres Shawinigan*
R. M. R. Higgins, *Ministry of Energy*
Al Rogers, *Ontario Hydro*

Question: Mr. Lewarne, *Morris Wayman Ltd.*
I'm a little confused, first of all, as to how much power is going to be generated. Acres Shawinigan tells us that there is going to be 19 megawatts, Ontario Hydro says 11.9, and the Ministry of Energy says 14, so there is a significant difference there. The other question is that I don't understand the difference between Ontario Hydro's giving of money to Hearst for generating that much power, however that much may be, and PUC is giving a substantial amount more. Do not PUC's operate where they purchase power from Ontario Hydro and resell it at a very low price, and PUCs' payments to the Hearst complex would increase because Ontario Hydro is charging them much more money than they're giving to Hearst for generating that power?

Answer: Mr. Rogers
The first question is relatively straightforward. As Bob Gudgeon outlined, we were originally looking at a higher quantity of wood waste than the one that was finally decided on as the quantity with which the plant should be designed. The difference, I think, was 156,000 oven-dried tons a year, that was the 19 megawatts, and finally, it was decided that the long-term availability of wood could only be guaranteed at about 129,000 oven-dried tons a year. This was due to some projections by the Ministry of Natural Resources in decrease of the timber availability from private lands. So that explains why that went down to 14 megawatts, which is the gross figure, and 11.9 is the net figure for the facility. Hydro of course based all their calculations on capacity credits on the net figure. Fourteen is the gross nominal capacity of the turbine.
To answer your second question: If the PUC controlled the wood-waste generating facility, they had agreed to pay the same rates (wholesale bulk energy rates) as they would normally pay Ontario Hydro for energy, which, as I said, are comprised of certain elements, all of them escalated over time. If the offer by Hydro, where Hydro would control the facility, was based on other normal arrangements that we make for the purchase of power, which includes a non-escalated capacity allowance, plus an energy component made up of incremental energy costs, primarily related to the cost of fossil fuel. The other difference, of course, is that where the PUC is in control, and paying the wood-waste facility bulk wholesale rates, then Ontario Hydro would have to get into the stand-by charge.

Question: Mr. Lewarne
Ontario Hydro has been telling us all day that they want to encourage cogeneration. It seems to me that if you have that huge gap that exists on that graph that was presented by Acres Shawinigan, between the profit that can be made by selling to PUC and a loss that can be made by selling to Ontario Hydro, then that doesn't seem like very much encouragement to me.

Answer: Mr. Rogers
I ended up saying in my presentation that Ontario Hydro would probably be willing to negotiate a contract based on the wholesale bulk powr rates, which will eliminate that difference and escalate the capacity allowance over time.

Question: Mr. Guy Drouin, *Ministry of Affairs, Quebec*
You have quite a complex project with quite a long critical path, and this project involves a lot of people, a lot of ministy agencies, municipalies even private companies. I would like to ask, how will you manage this project? Is it a task force approach? I would like to get some feeling about the way you can manage this project for the next two years.

Answer: Mr. Rogers
I think that's an extremely important question in this topic that we're dealing with. Roger, would you like to handle that one?

Answer: Dr. Higgins
Well, to this point, it was managing the worst possible way; that's government by committee. I would agree with you entirely for the future, if anybody has any hope of implementing this within a reasonable time frame, that that is not the way to go. I think, though, if we presume that we go the way of a request for private proposals, that it's quite within the capability of the participants, plus consultant, to fairly quickly, (with the information that's currently available, after the subsequent discussions,) get that request for proposals together in reasonable shape. What we would then be looking for is somebody who can basically also take over the whole management and the critical path scheduling and so on, of the facility, who would have a financial participation hopefully, that at the very least would be providing all of the construction design, final design, construction management and so on, for whatevery operating authority. Now the question of the operating authority is still wide open. There could be a number of possible combinations; maybe a company from the private sector would wish to take out an equity position in the operation. It could become part of the operating authority. That would be a question within the request for proposals, probably, if we went that route, which would affect how the ownership was set up. But, basically, it has to be turned over to the private sector as soon as possible to complete the job; otherwise, it's going to drag on interminably.

Question: Mr. Drouin
I would like to have an idea who is the promoter of this project? Who wants to sell to whom, because

you deal with the lumbermen, you deal with a lot of people . . .

Answer: Dr. Higgins

There's no question that the government is there to assist the lumberman . . .

Question: Mr. Drouin

So the lumberman is the leader of the project?

Answer: Dr. Higgins

Yes. And if they wish to tell us to go away and they want to do something else, that's fine. As I said to you, the lumbermen are considering participation with a private sector company in the preparation of prepared fuel, wood pellets, and they basically asked us to go into a holding pattern on this particular concept, on the co-generation concept, until the private sector has fully developed that proposal and made a commitment one way or another to go ahead or not, so let's get it very clear that the government is not out to promote this particular project. We are, I think, as being an energy conservation department, very interested in promoting the concept of co-generation and so on; otherwise, we wouldn't be here today, but not this particular project. We were brought in at the request of the municipality and the lumbermen.

Question: Mr. Planzer, *Dominion Textile Ltd.*

I missed two small points in the presentation by the Ontario Ministry of Energy. There was capital cost stated - about 22.6 total, 84.5 million kilowatt hours per year. What was the overall cost per kilowatt hour?

Answer: Dr. Higgins

I don't have that particular figure on the slide. It's probably in the report. Maybe you could see me after . . .

Question: Mr. Planzer

The other question. Wood waste - is there a cost to it? Is it being sold?

Answer: Dr. Higgins

This is a point of negotiation, but the concpet was that the facility would collect the wood waste at zero cost, F.O.B. the plan or the lumber mill. They would then incur a transportation cost. That cost was estimated at about, in the initial period, $350,000 a year. That's between $2.00 and $2.50 a ton. So there would be a net cost to the facility. That again, is a point of negotiation and there has been discussion about them paying a disposal fee on a declining basis and so on, and this is one of the sort of points of negotiation, one of the areas of give, if you like, but it has to be considered when negotiating on this project.

Question: Gaston Boucher, *Hydro Quebec*

This is not really a question, but you keep calling your project a cogeneration project. There is very little cogeneration because you have a capacity of 186,000 pounds of steam per hour, and your low pressure steam usage was only about 78,000 pounds, and even after that you found out that your needs are even lower. So, for a project to be feasible, we found out through our studies, that you have to find a customer for the heat; otherwise, it's very hard to make it economical or profitable. Secondly, you have 14 megawatt capacity gross. You have a plant cost of $22 million and in brackets, right beside, you have $660 per kilowatt. How do you arrive at that figure?

Answer: Dr. Higgins

Well, the $1,600 per kilowatt was the total cost divided by the kilowatt output. The $660 refers to the electrical energy on the heat output converted to kilowatt hours. That's the total energy output - $660 a kilowatt. There's no comparison on that kind of unit because you're mixing heat and electric power so they're both meaningless, really.

Thermodynamic Theory of Cogeneration

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Professor W. D. GILBERT
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This paper introduces the principles of cogeneration through a discussion of energy terms, heat engines, power production, "available and unavailable" energy and the various technical criteria for efficient generation of power such as power available from steam, energy balance in condensing cycles, back pressure power and extraction turbines. It also discusses some of the new developments and the technologies that may be used in cogeneration systems including direct thermocompression, heat pump cycles, and special working fluids for heat transport.

Introduction

Energy can be divided into two types or grades: Available Energy and Unavailable Energy.

In thermodynamics, available energy means energy which is available to do mechanical work. This terminology originated with Lord Kelvin many years ago and has since been used in thermodynamics. It is sometimes termed availability, however people other than thermodynamicists use the term available energy to indicate energy which can be mined, purchased, or supplied, this leads to some confusion. To eliminate this confusion, it has been suggested that the energy which can be transferred to mechanical work be termed "EXERGY" or an A, B, or ơ function (Burkhard and Basler (1)*, Keenan 1932 (2), Hayward 1974 (19)). The American Institute of Physics in Report number 25 of 1975 entitled "Efficient Use of Energy" (AIP Conf. 1975 (3)), uses the term "available work" for energy which can be transferred to mechanical work. They also indicate that the concept of available and unavailable energy is unfamiliar to most physicists even though it appears in most engineering thermodynamics texts.

The portion of the energy which cannot be transferred to mechanical work is termed unavailable energy by thermodynamicists. As with the term "available energy", the term "unavailable energy" is often used by other people to indicate energy which cannot be obtained from the earth or by purchase, and it is suggested by some that energy which cannot be transferred to work be termed as "ANERGY". It should be noted that the terms available and unavailable, in thermodynamics, refer to production of mechanical work.

*The numbers in parenthesis designate References at the end of the paper.

Both available and unavailable energy are useful in heating. However increase in the temperature required by the heating task demands an increase in the fraction of the energy used which is available. Sometimes we say that energy with a large fraction available is low grade. Mechanical work and electricity are the highest grade; in theory, electricity can all be transferred to mechanical work. Using electricity for heating, is using high grade energy for a task which can be done by low grade energy. (Electric heating may have advantages which outweigh this disadvantage). The International Institute of Applied Systems Analysis used the term "negentropy" (Hafele 1975 (4)) as a measure of energy which can be transferred to mechanical work; that is which is available in the thermodynamic sense. Entropy is a measure of the unavailable fraction of the total energy, so they use negentropy for the opposite of entropy. Even though the terms, "available" and "unavailable" are used by the general public with meanings quite different the thermodynamic meaning, it is very doubtful if the introduction of other terms has done anything to clarify the concept of available and unavailable energy. However we should take note of these new terms perhaps for no other reason than the prestige of their proponents.

Even though it is very elementary it is thought desireable to insert here the method of determining the available part Q_A and the unavailable part Q_R of a quantity of heat Q.

$$Q_R = \frac{T_O}{T} Q \qquad Q_A = Q - Q_R = \left[1 - \frac{T_O}{T}\right] Q$$

Where T is the temperature of the material from which or to which heat is flowing. T_O is the

temperature of a heat sink to which heat can be rejected. Usually the temperature T varies as the heat flows and the mathematics has to account for the changing temperature. It should be noted that there is no destruction of energy; the heat taken from one substance is given to a second substance. However the temperature of the second substance is lower than the temperature of the first, so that the unavailable part increases and the available par decreases on heat transfer; and energy is degraded. It might also be noted that Q/T is the entropy charge and the entropy of the hot substance decreases while the entropy of the cold (second) substance increases. However there is an entropy increase for the two substances together; the entropy increase of the cold is greater than the entropy decrease of the hot. Entropy is a measure of the unavailable energy which equals the product of entropy and T_0.

The first task of a normal thermal electric generating station is to produce mechanical work and then electricity from a supply of thermal energy. The thermal energy is only partly available and it is only this part which can be transferred to electricity. The unavailable energy is rejected to the cooling water, and then to the lake or river. Due to imperfections in the plant, some of the energy which was available in the thermal energy supplied is also rejected to the cooling water i.e. some of the energy originally available becomes unavailable due to heat transfer and friction and is rejected with the energy which was originally unavailable. If there is a second task requiring heat at the temperature of the plant exhaust, the unavailable energy rejected by the plant can be used for this task. Usually the second tasks require heat at a higher temperature than the normal exhaust and it is necessary to use for the second task energy which has some fraction available. The exhaust temperature may have to be raised so that the energy rejected by the part of the plant producing electricity is useful for this second task. Stated very simply the concept of By-Product Power or Co-Generation is the use of the available energy in the thermal supply for the supply for the production of electricity, and the use of the unavailable energy in this supply for heating.

It should be noted that the electricity and the heat are produced at the same instant, and unless some method of storage is devised they must be used at the same time. One part of this problem would be solved if the electric utility agrees to absorb, at a reasonable price, the electricity that the industry produces when it has a demand for heat but has less than the corresponding demand for electricity. However, it is not easy to determine or agree on a reasonable price for this electricity. The other side of the problem is the supply of electricity to the industry when it has a small or no requirements for heat. If the utility supplies this electricity, what should it charge for the energy and the capacity or facilities?

It should also be noted that, if there is a large demand for heat (low grade energy), it does not matter if the turbine is efficient or not. If it is efficient it takes more energy from the steam than it takes if it is inefficient. An inefficient turbine leaves more energy in the steam where it is valuable because it can be used as heat where it is required.

The atmosphere contains energy but it is not very useful for heating a house. A heat pump can be used to add available energy (work from a motor) to energy obtained without cost from the atmosphere, so that the two together can be used to heat the house; the majority of the energy supplied to a house by a heat pump comes from the atmosphere. The task of heating a house requires only low grade energy; but not quite as low grade as that in the atmosphere.

In some processes there is an excess of energy which is much higher grade than that in the atmosphere, but not a high enough grade to perform the tasks for which energy is required in the plant. A heat pump can be used to upgrade this energy so that it, along with the available energy supplied by the motor of the heat pump, will perform the tasks required. Because the original excess energy is higher grade than the energy in the atmosphere the requirements for electrical energy (available energy) are smaller than they would be if the original energy came from the atmosphere.

If the excess of energy is in steam and the tasks requires steam at higher temperature and pressure (higher grade) the energy can be up-graded by adding available energy in a steam compressor.

Industrial Steam Power

Steam power cycles historically used reciprocating steam engines. Although they have many favourable characteristics, the size, weight, cost and the limitations on output of engines have meant that steam turbines have taken over the field. While many practising power engineers today may enjoy reflecting upon earlier days with reciprocating engines, few would care to operate a large reciprocating engine plant with today's operating and maintenance costs. Therefore we will confine our discussions of steam power to turbines, especially since they can be designed for a wide range of outputs and steam conditions.

Analysis of power cycles, however complex, consists of the combination of relatively simple elements. The analytical performance of certain ideal models is straightforward. The more complicated performance of actual plant components can then be compared to the ideal by efficiencies, which for our purposes can be obtained from our own experience or the published values of others.

Vapour Power Cycles

The conversion of thermal energy to work in a vapour power cycle in the simplest case takes place in cycle consisting of boiler, turbine, condenser and feedwater pump. H_2O is the preferred working fluid although for special reasons another fluid might be practical. For yardstick purposes we use the Rankine Cycle, Figure 2.1.

The turbine (or engine) receives high pressure steam at point 1 which may be superheated, and expands it to

the exhaust pressure, point 2. The exhaust steam is condensed at constant pressure to saturated liquid, point 3. The condensate is then compressed to the initial pressure. Since this is liquid being compressed, the

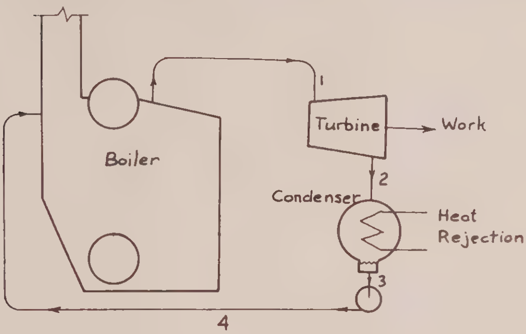


Fig. 2.1: Rankine Cycle Components

work required is quite small compared to the turbine output. (although the absolute quantity may be high). The boiler then adds thermal energy to the fluid at constant pressure to bring if from liquid, point 4, to the initial conditions, point 1.

Modern cycles built for power generation are far more elaborate than this, employing regenerative feedwater heating and reheating. We do not need to go into these details here, because a sufficiently clear picture can be obtained from the basic cycle.

The performance of turbines will be discussed in more detail. The work produced per lb. of steam depends on the difference in energy of the steam as it expands for point 1 to point 2. This can be read off a Mollier diagram or from Steam Tables. The thermal energy input to the cycle per lb. of steam is (h_1 - h_4) and the work input is (h_4 - h_3).

High initial steam pressure and temperature plus low exhaust pressure will maximize the work produced. However, capital cost and maintenance costs are important as well, particularly with industrial plants, since the provision of utilities is a service and an overhead. The most popular steam conditions are likely to correspond to the maximum steam temperatures that can be employed without advancing to a higher alloy class for superheater, piping or turbine materials. The turbine (or engine) is the key to the energy conversion. It is necessary to examine its performance.

2.2 Simple Steam Turbine Performance

The basic turbine stage is a row of stationary nozzles which expand steam against moving blades. The moving blading changes the steam direction and momentum and in doing so experiences a force which develops the torque the blades exert on the rotor. In travelling through the blading the steam may be further expanded (reaction blading) or undergo a momentum change without a pressure change (impluse blading). Such stages can be repeated to divide the energy conversion in manageable steps. The characteristics of turbines that are important in co-generation can be presented fairly simply.

2.2.1 Rankine or Ideal Turbine

The Rankine turbine has easily predictable performance that provides a convenient baseline for calculation of actual turbine output and steam consumption. The steam expands without heat transfer (adiabatically) and without fluid friction or losses. Thermodynamically, the process is reversible and isentropic. Given the intitial conditions (pressure and temperature, for instance, for superheated steam) the expansion will proceed at constant entropy to the exhaust pressure. Since there is no heat loss

$$\dot{m}\,(h_1 + KE_1 - h_2 - KE_2) = \dot{W}$$

The inlet kinetic energy is negligible and since in most turbine arrangements the exhaust kinetic energy would be a loss, we will set it to zero for the Rankine turbine. Then

$$\dot{m}\,(h_1 - h_{2s}) = \dot{W}$$

Checking up on units, Eng. System first:

$\dot{m}$ is the steam flow rate, lbm/hr usually

$\dot{W}$ is the power output, and HP or KW are most common

H_1 and h_{2s} are enthalpies in $\frac{\text{Btu}}{\text{lbm}}$

The equation of course needs constants to be consistent in Engineering Units

$$\frac{\dot{m}(h_1 - h_{2s})}{3413} = \dot{W} \text{ (kilowatts)}$$

$$\frac{\dot{m}(h_1 - h_{2s})}{2545} = \dot{W} \text{ (horsepower)}$$

SI units are simple, although some experience is needed before the numbers have a "feel" one can use with confidence.

Rearranging:

$\frac{\dot{m}}{\dot{W}}$ is the mass per unit of work output

and is equal to $\frac{3413}{h_1 - h_{2s}}\ \frac{\text{l b m}}{\text{KW hr}}$

$$\frac{2545}{h_1 - h_{2s}}\ \frac{\text{1bm}}{\text{HP - hr}}$$

Since we are dealing with an ideal turbine without losses, this is the Theoretical Steam Rate (TSR). Since the enthalpies are determined by the inlet conditions, a constant entropy path and a specified exhaust pressure, the TSR can be calculated from a Mollier diagram, computer program, or from tabulated values (Theoretical Steam Rate Tables, (5)).

2.2.2 Actual Turbine

Assuming an adiabatic turbine (quite realistic), the *internal work* done by the steam is $(h_1 - h_2)$.

To relate the performance of an actual turbine to that of an ideal turbine, first look at the losses that can occur.

These fall into two basic classes:

(a) Those that occur outside the turbine casing, reducing the net output, but not affecting the thermodynamic process inside. Examples are bearing losses, electrical losses and the power to drive lubricating oil pumps or other attached auxiliaries.

(b) Losses that reduce the conversion of thermal energy to work inside the turbine casing. Examples are kinetic energy of steam leaving stages that cannot be effectively recovered, viscous and boundary layer effects, disc friction and interstage leakage. The effect of these losses are to reduce the work output per unit mass of steam resulting in a correspondingly larger exhaust enthalpy.

The internal conversion of thermal energy to work is less in the actual turbine. Defining the internal efficiency

$$n_i = \frac{\text{Internal work, actual turbine}}{\text{Internal work, Rankine turbine}} = \frac{h_1 - h_2}{h_1 - h_{2s}}$$

The ground rules are: same inlet conditions, same exhaust pressure.

This relation can be displayed on either a T-s or Mollier diagram, Figure 2.2.

The internal output of the actual turbine is then

$$W_i = n_i \frac{\dot{m}(h_1 - h_{2s})}{3413} \qquad \text{(for KW)}$$

The work available at the coupling or generator terminals (as appropriate) will be reduced further by the mechanical-electrical efficiency (to allow for losses in (a)).

$$\dot{W} = n_{me}\, n_i \frac{\dot{M}(h_1 - h_{2s})}{3413} \qquad \text{(for KW)}$$

The steam rate of the actual turbine is related similarly to the TSR.

$$SR = \frac{3413}{n_{me}\, n_i\, (h_1 - h_{2s})} \qquad \text{(for KW)}$$

or very simply from the TSR

$$SR = \frac{TSR}{n_{me}\, n_i}$$

The product $n_{me}\, n_i$ can be expressed as a single efficiency, the engine efficiency, n_e.

Turbines used in power generation have several sections generally with different mass flow rates. Individual sections can be dealt with one by one using the steps above.

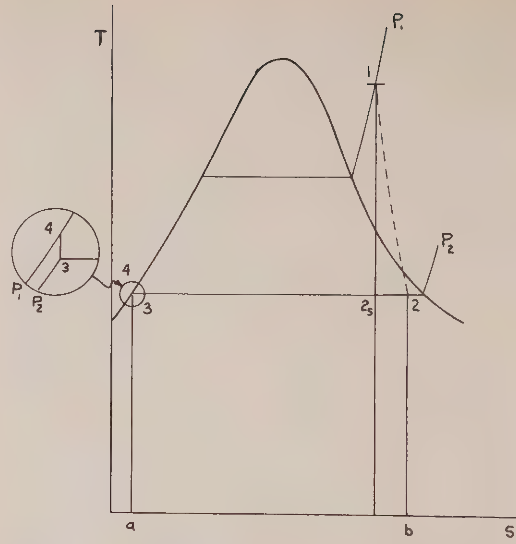


Fig. 2.2: Temperature-Entropy Diagram for Simple Steam Power Cycle.

2.2.3 Variation in Output

An ideal turbine always expands steam from the specified inlet conditions without friction to the exhause pressure. Variation in output is accomplished without introduction of losses. Actual turbines incur additional losses in changing output. Looking first at the losses in (a) above.

(a) If speed is constant, bearing losses, and most auxiliary drive losses do not change. Some electrical losses (I^2R for instance) will be reduced while others will stay constant with voltage. The net result is that this class of losses will become a greater fraction of the output as load is reduced.

(b) The internal losses will include a new component at reduced load which will predominate even if other internal losses are reduced. Reduction of output would ideally be accomplished by reduction of mass flow while keeping the enthalpy drop the same. In fact both are reduced. Two processes are depicted, Figure 2.3.

   (i) Throttling which keeps the inlet enthalpy constant while reducing the pressure. It can be seen that the enthalpy drop is reduced as well, accompanied by strong non-reversible effects and an increase in entropy.

   (ii) Nozzle governing which ideally would reduce the area for inlet flow alone. However, some throttling occurs as well, although the part load performance is not degraded as strongly as with throttling.

Looking again at the equations, the TSR stays constant at all loads provided the inlet steam conditions and exhaust pressure are kept the same. The relative

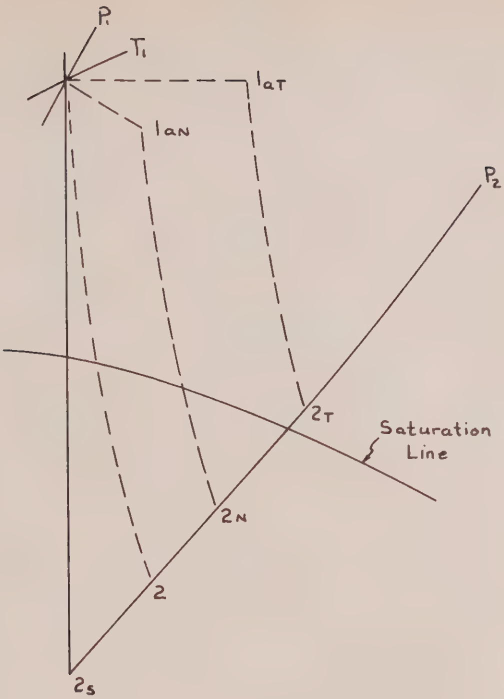


Fig. 2.3: Mollier Diagram Showing Part Load Performance.

increase in losses means that the SR climbs as load is reduced. These relations agree well with observed behaviour. Historically, the steam consumption vs. output plot is the Willans line, a very fair approximation for most simple steam turbines, Figure 2.4.

The relation is linear with a no load intercept on the zero power axis. This intercept is not important operationally, since the unit would seldom be run at no load except for very brief periods. However, its value controls the slope of the line and may be important for calculations.

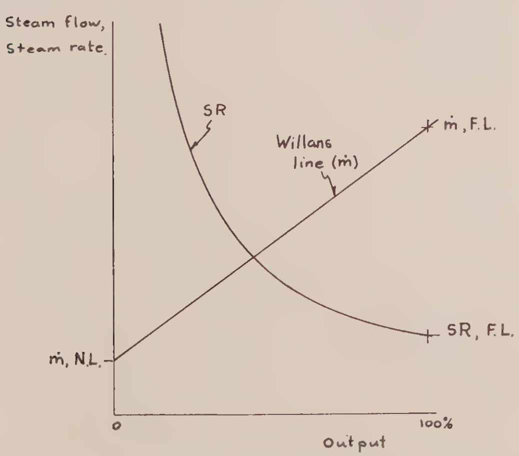


Fig. 2.4: Willans Line and Steam Rate.

The quotient $\frac{\dot{m}}{\dot{W}}$ is of course SR, and has the calculated full load value at 100% power and an infinite value at no load.

If SR increases as load is reduced, the exhaust enthalpy must increase, reflected in the Mollier diagrams, Figure 2.5. and internal work is greater than the electrical or mechanical output, i.e.

$$\frac{(h_1 - h_2)}{3413} = \frac{\dot{W}}{n_{me}} \quad \text{(True at all loads).}$$

If n_{me} is given (or estimated) at part load and the steam conditions stated, h_2 can be calculated from the output. Then, using this enthalpy and the exhaust pressure the exhaust temperature can be checked(in case excessive temperature requires desuperheating).

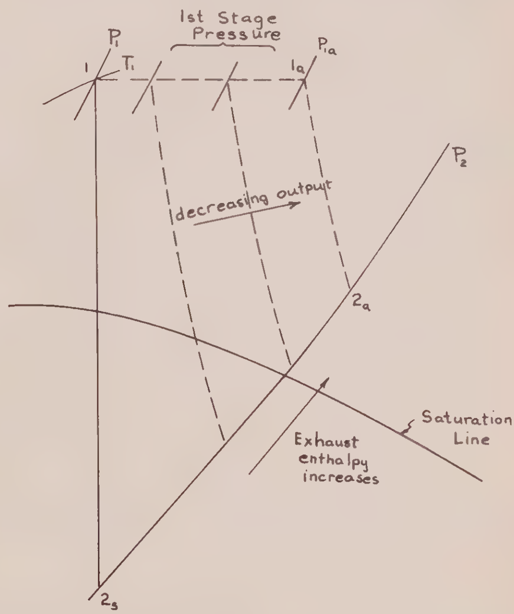


Fig. 2.5: Increase of Exhaust Enthalpy at Part Load (Example for Throttle Governing).

2.3 Application of a Steam Turbine to Cogeneration

The expansion process through a simple turbine is shown on the T-s diagram with exhaust state h_{2s} (ideal) and h_2 (actual), Figure 2.6. The lowest temperature for heat rejection is T_o. With no internal losses there is no increase in entropy in the ideal turbine. Looking at the change in available energy per unit mass of steam we have $(h_1 - T_o s_1) - (h_2 - T_o s_{2s})$. Since $s_1 = s_{2s}$ in the ideal case, we have the change in available energy in an ideal turbine exactly equal to the work done.

If there is 100% conversion here why do steam power cycles have efficiencies ranging from 40% on down (even with an ideal turbine)? The turbine itself, especially in larger sizes, converts available energy ex-

tremely efficiently. However the 2nd law requires that heat be rejected, and for cycle 1-2_s-3-4 the rejected heat is (h_{2s} - h_3) or area a-3-2_s-c can be used for heating purposes provided temperature T_2 is high enough to be useful. Here lies the key advantage of combining heating and power applications. The energy which must be rejected from a power cycle is used for heating which can utilize both available and unavailable energy. The turbine makes effective use of available energy. The heating process uses residual available energy plus a large amount of unavailable energy.

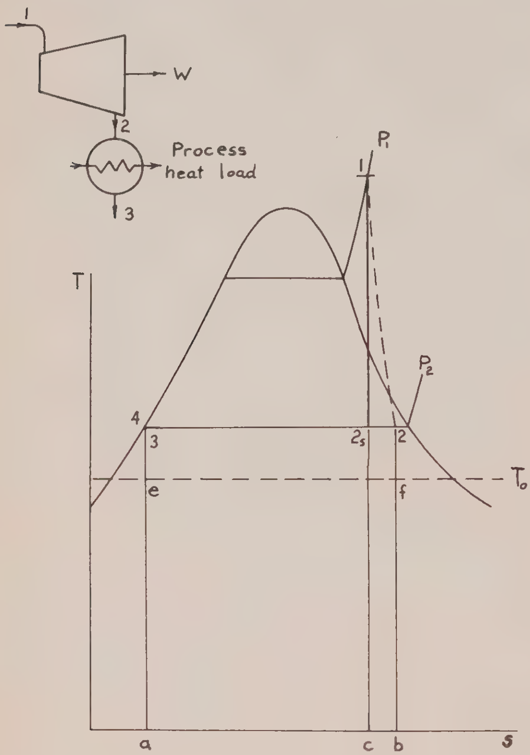


Fig. 2.6: Back Pressure Turbine Showing Available Energy Quantities.

The combination carries a penalty. In order to take advantage of the energy in the exhaust it must be at a useful temperature. This means higher exhaust enthalpy and reduced work per unit mass. Nevertheless the advantages, properly exploited, can be surprising. We shall examine the thermodynamics of such schemes. First a look at the above relations in an actual simple turbine.

In an actual expansion process there has been an increase in entropy from s_1 to s_2 and a change of available energy in steam of:

$$b_1 - b_2 = (h_1 - T_o s_1) - (h_2 - T_o s_2) = (h_1 - h_2) + T_o (s_2 - s_1) = W_i + T_o (s_2 - s_1)$$

i.e. the change in available energy of the steam shows up as internal work, W_i (the bearings and generator losses will take a small toll) and the term T_o (s_2 - s_1). The work delivered is 100% available by definition. Remember that W_i is less than the corresponding quantity for the ideal turbine because of the internal efficiency, n_i.

The quantity $T_o (s_2 - s_1) = T_o (s_2 - s_{2s})$ is an additional unavailable portion of energy over that in the exhaust from an ideal turbine.

Again, however provided that T_2 is high enough for space or process heating, an amount of energy can be transferred to the process equal to h_2 - h_3 or area a-3-2-b on the T-s diagram. The extra unavailable energy resulting from internal losses in the actual turbine is now much less significant since both available and unavailable energy are exploited in the heating process. Remembering that elevating the exhaust enthalpy to achieve practical values of T_2, we would not want unreasonably large turbine internal losses since the internal work is being penalized already.

Example

Finding the steam requirements and exhaust temperature of a simple steam turbine which supplies both electricity and heating steam:

Initial steam conditions	- 400 psig, 600°F.
Exhaust pressure	- 120psig
Power requirement	- 2000 KW

Solution by Theoretical Steam Rate

References "Modern Turbines" Newman et al. (6)
"Steam Turbines and Their Cycles", Salisbury (7)
"Theoretical Steam Rates", ASME. (5)

TSR = 31.50 lb/kw hr
h_1 = 1306.2 Btu/lb

We need the steam rate of 2000 kw turbine operating under the given conditions.

- Newmann gives TSR factor = 1.49
- Salisbury gives combined internal and mechanical efficiency (engine efficiency) = 68.2%
- The TSR factor corresponds to an engine efficiency of 1/1.49 = 67.1% which agrees fairly well.

$$SR = \frac{TSR}{n_i} = \frac{31.50}{0.682} \; 46.2 \frac{lb}{kw\ hr}$$

$$\dot{m} = 46.2 \times 2000 = 92{,}400 \text{ lb/hr}$$

To find the exhaust temperature it is necessary to find the exhaust enthalpy. First find the internal work. For turbines of this size at full load, Newman gives

$$h_1 - h_2 = \frac{3600}{SR \text{ (full load)}}$$

which includes a combined mechanical and electrical efficiency of 94.8%.

$$h_2 = h_1 - \frac{3600}{SR}$$
$$= 1306.2 - \frac{3600}{46.2} = 1228.3 \frac{BTU}{lb}$$

This corresponds to a temperature of 410°F.
Saturation temperature at 120 psig 350°F.
Superheat of the exhaust = 60°

This is a fairly satisfactory value of superheat in the exhaust.

If the exhaust steam is condensed to saturated liquid at 120 psig the energy that can be transferred to the process will be

$$Q_p = m(h_2 - h_3) \text{ (Area a-3-2-b in Figure 2.6)}$$
$$h_2 = 1228 \text{ Btu/lb}$$
$$h_3 = \underline{322}$$
$$906 \times 92400 = 83.7 \text{ million } \frac{\text{Btu}}{\text{hr.}}$$

When this energy Q_p is useful in the space or process heating, the only losses in the whole cycle will be; boiler losses, the mechanical and electrical losses of the turbine generator, and any heat losses to the environment from the piping etc. These losses can easily be reduced to 20%, and 15% is a realistic target.

Note that if the internal efficiency of the turbine is reduced, available energy will be degraded and less work produced per unit mass of steam. However, the exhaust enthalpy will be correspondingly higher, allowing more heating to be done. This means that in smaller turbines where high internal efficiency is harder to obtain at modest cost, the overall picture can still be quite favourable.

However, it would not be wise to accept extremely low internal turbine efficiencies just because the exhaust is used for heating. Electrical demands have shown a historic upward trend as more automation, etc. is used, while heating demands are being reduced by improved building insulation, ventilation techniques, etc. A turbine with low internal efficiency that may fill the bill today, might well be an embarrassment in the future.

2.4 Balance of Power and Heating Loads

This example will illustrate some further factors. Suppose the electrical load were to remain at 2000 kw., while the heating demand fell to 30 million Btu/hr. because of a process unit being out of service. The turbine requires 92,400 lbm/hr. steam flow as before.
The heating mains can only accommodate

$$\frac{30}{83.7} \times 92{,}400 = 33\ 118 \text{ lbm/hr.}$$

In other words this simple arrangement cannot vary electrical and thermal outputs independently. However there are alternatives

(a) Generate electricity in quantities that will supply the required heating steam. Buy any additional power required.

(b) Blow off excess exhaust to atmosphere.

(c) Use a condenser to handle the excess exhaust.

Alternative (c) has the advantage of conserving feedwater. Since for cheapness the condenser will normally be constructed for pressures about atmospheric, nearly all the energy in the exhaust will be rejected.

Alternative (b) sounds unacceptably crude. However, for short periods or emergencies it could be very attractive.

Alternative (a) looks the best from an overall point of view, provided the additional power is being generated in a highly efficient plant. However in the face of a block demand rate structure with rachet provisions, many operators would use alternative (b).

When more heating steam is required than would pass through the turbine to meet the electrical load the inverse problem occurs. Again there are several alternatives.

(d) Run the turbine at a load that will provide the required exhaust flow and sell the excess power to the utility system.

(e) Throttle high pressure steam into the heating main.

(f) Supply steam from low pressure boilers.

Alternative (d) again provides a good solution from the overall point of view, again providing that suitable financial and other arrangements can be negotiated for parallel operation.

Alternative (e) is simple and certainly desirable to cover emergencies or other short term requirements.

Alternative (f) would require maintenance and operation of another set of boilers.

It can be seen that where the heating and power loads are fairly well balanced and parallel operation with the utility system is possible, the simple back pressure turbine generator is a very attractive arrangement. It is uncomplicated, remarkably efficient, and has a good record for reliability.

An interesting further possibility is siting such units where a number of users are close enough that the exhaust energy can be either imported or exported through steam or high temperature hot water mains.

2.5 Condensing Operation

If the power requirements are large in relation to the heating load, we could consider an elaboration on (c) for handling excess power requirements. Instead of throttling excess exhaust steam to the condenser, which wastes available energy, expand it through a condensing turbine to a low pressure. Looking into this more closely to get a feel for the numbers, suppose that circulating water is available to give an exhaust pressure of 2 inches Hg absolute. Looking at the internal work per lb mass;

1. from 400 psig, 600°F. — h_1 1306.2
   to 120 psig, 405°F. — h_2 $\underline{1228.3}$
   Internal work/lbm — 77.9 Btu/lb.
   $$n_i = \frac{.682}{.947} = 0.72$$

2. from 120 psig, 410°F. — h_2 1228.3
   to 2'' Hg at constant entropy — h_{2s} $\underline{905.0}$
   Work/lbm, ideal turbine — 323.3 Btu/lb.

To find the internal work of this condensing section for an actual turbine, from Salisbury n_1 n_{em} 70%, giving an internal efficiency $n_i = 73.7\%$. This is a bit higher because of the greater volume flow.

work/1bm actual = 323.3 x .737 = 238.3 Btu/1bm.

The internal work per 1b of steam in the condensing section is just about three times the work done by a pound of steam expanding from initial conditions to 120 psig. This is a remarkable quantity of power. Remember that in exploiting it we are abandoning our basic principle of recovering rather than rejecting energy from the exhaust. However, the amount of steam to be condensed can be kept small if the initial design has been done carefully, remembering that steam which produces power by condensing expands through the whole range from main steam conditions to exhaust.

The combination of a back pressure turbine and condensing turbine is an extraction turbine. The incorporation of both sections in a single casing means fewer bearings, one generator, simpler foundation, etc. Again these advantages are not without penalties.

2.6 Extraction Turbines.

A simple extraction turbine has one or more openings through the casing which lead to inter-stage areas so that steam can be extracted instead of expanding through the rest of the stages (British: pass-out turbine, English Electric (8) Lyle (9))). The pressure of the steam at an extraction point will vary with mass flow through the following section.

Where no arrangements are made to control steam flow, except for the turbine inlet governing valves, the pressure of steam available at an extraction point will vary according to the steam flow and load on the turbine, hence the term uncontrolled extraction. Figure 2.7 shows how the pressure at an extraction point would vary with throttle steam flow when no steam is being extracted ($\dot{m}_2 = 0$).

If the flow $\dot{m}_1$ is kept constant and steam is extracted, increasing $\dot{m}_2$, two things will happen. The turbine output will be reduced because less steam will flow through the low pressure section and also the pressure at point 2 will fall.

In some situations this is satisfactory, for instance extraction feedwater heating. However most process load require that the steam pressure stay constant. Perhaps you can recall discussions with a process foreman on the subject. To maintain constant extraction steam pressure when the mass flow, $\dot{m}_3$. (British: pass through valves). The governing system then regulates turbine speed and extraction pressure within the available range. The operations of this governing gear is very interesting, but beyond the scope of this discussion.

Note that the flexibility produced by this system brings with it penalties.

(a) Condensing operation causes energy rejection from the cycle.

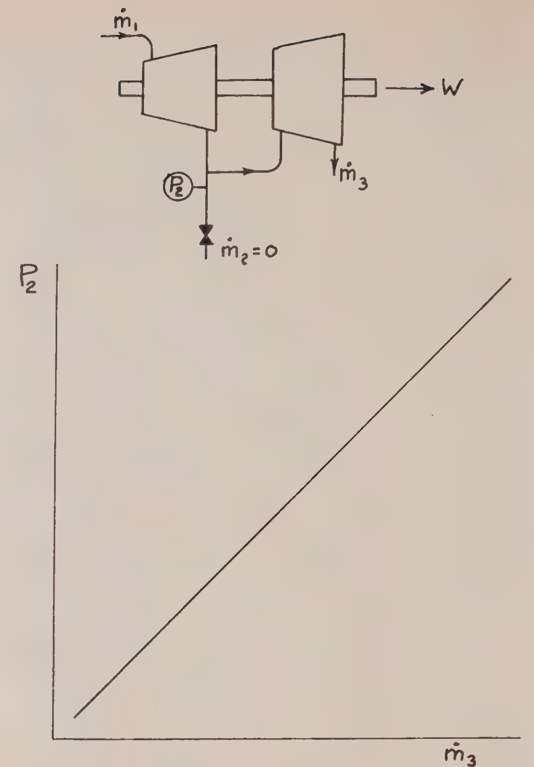


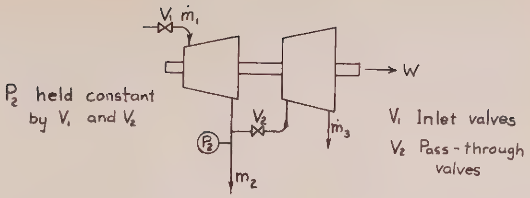
Fig. 2.7: Pressure Variation at an Uncontrolled Extraction.

(b) When the load balance allows the turbine to operate with a very small flow to the condenser, the condensing section is operating at essentially no load conditions. This means it contributes very little power and in fact it may require power to spin it. Provision has to be made to provide cooling steam through the condensing section to prevent excessive temperatures arising because of windage when the condensing flow is at its minimum. (10) The simple Willans line diagram is expanded for an automatic extraction turbine. Figure 2.8. The line E_0 corresponds to zero extraction.

At a given output, if the extraction is increased, more steam has to be admitted through the throttles to compensate for the extracted steam. Remember that the flow between the extraction point and the condenser is reduced and hence also the work output between these points.

The result is that lines of constant extraction flow can be plotted which are essentially parallel to the simple Willans line for zero extractions.

The turbine discussed above is a single automatic condensing unit. i.e. there is one controlled extraction and the exhaust is condensed. The exhaust could be arranged to be at a pressure above atmospheric and used for heating at a lower temperature than the extraction



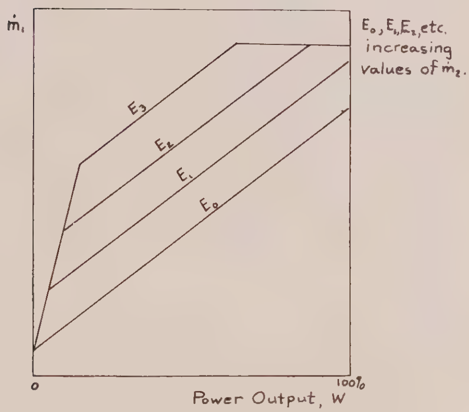


Fig. 2.8: Performance of a Single Automatic Extraction Turbine.

steam. This is a very desireable unit thermodynamically because it avoids heat rejection to the environment and would be termed a single automatic non-condensing unit.

A more complicated turbine could be provided with two controlled extractions i.e. a double automatic extraction unit, and designed to be either condensing or non-condensing. Naturally the performance diagram would be more complicated (11).

If for some reason steam could get back into the turbine from the extraction piping it could expand to exhaust pressure and, under some conditions, overspeed that turbine. Hence reliable non-return valves are required, unless some other overspeed protection is provided.

2.7 Mechanical Drive Extraction or Back Pressure Turbines

The above applications have been discussed where electrical power is to be generated at the same time that process heating loads are met. The mechanical work can in some cases be supplied directly to the load, for instance turbocompressors and pumps. Steam or gas turbine drives are advantageous where compressors or pumps benefit from variable speed. This is not cogeneration in the sense of producing electricity. However, mechanical power produced within the plant reduces the transmission and generation equipment required by the electric utility as well as providing very economical by-product process energy.

3.1 Gas Turbines and Diesel Engines

The steam turbine adapts to cogeneration schemes because the exhaust can be used for process or space heating, either directly or via high temperature hot water transmission.

Diesel engines and gas turbines are attractive as prime movers where self contained units are required. They require high grade fuels in most applications which makes maximum utilization of the energy very important. The exhaust contains considerable energy at useful temperatures (generally 700 - 950°F.), but direct transmission of the hot gas is awkward because of its volume.

However an exhaust heated boiler or heat exchanger can recover energy in a useful form. Several characteristics of such a boiler are quite interesting.

(1) It is important to limit the back pressure imposed on the gas turbine. Typical figures are 0.25% reduction in gas turbine output per 1 inch H_2O increase in back pressure.

(2) A lower limit of exit gas temperature may be necessary due to the corrosive potential of the combustion products.

(3) There is a considerable oxygen content in the gas turbine exhaust, so that supplementary firing can be used to boost the steam production for short term peaks or other reasons.

(4) The exhaust gas cools as energy is extracted from it. The temperature of the water - steam circuit follows the usual heating, evaporation -superheat pattern, Figure 3.1. The mass

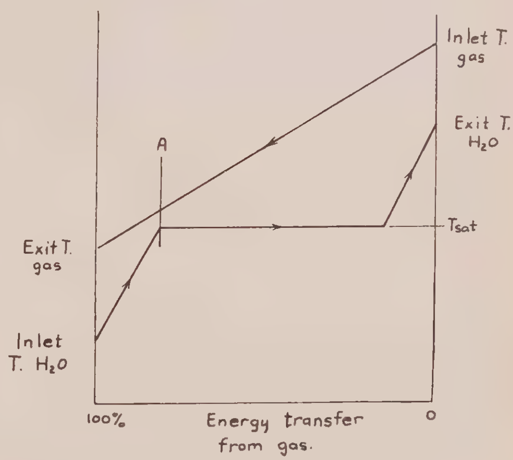


Fig. 3.1: Temperature History in a Heat Recovery Boiler.

flows, heating surface, and flow patterns must be arranged so that an adequate temperature difference exists to transfer heat.

Diesel engine exhaust heat recovery is similar and of great value in remote locations, where fuel transportation costs swamp out the penalty attached to high grade fuel. A very rough rule of thumb is to divide the

energy input of the fuel into three approximately equal parts - power output, exhaust energy 'and heat to jacket water. Turbocharging can alter this a bit. Recovery of heat from both jacket water and exhaust is feasible and useful.

Example (Data adapted from commercial literature)

An aircraft derivative type gas turbine package with output 2000 kw and SFC o.64 lb/kw. hr. is to be connected to an unfired heat recovery boiler. The exhaust gas leaves the engine at 37.2 lbm/sec. at 900°F. and leaves the boiler at 250°F. Feedwater enters the boiler at 180°F. and steam leaves at 120 psig, 410°F. (to be comparable to the previous example).

Checking the energy recovered from the exhaust gas using thermal properties from Keenan and Kaye for 400% theo. air at 900°F. and 250°F.

$$\dot{m}\,(\Delta h) = 37.2\frac{(9785.5 - 4973.1)}{28.954} \times 3600$$
$$= 22.257 \text{ million Btu/hr.}$$

For the steam system

steam, 120 psig,	410°F.	h =	1227.3 Btu/lb.
water	180°F.	h =	148 "
			1079.3

Energy transferred to water

$= \dot{m}\,(1227.3 - 148) = 22.257 \times 10^6$

steam flow, $\dot{m} = 20{,}615$ lbm/hr.

There is a point that must be checked in a set up like this. The temperature difference between the exit steam and the hot gas is 900 - 410 = 490° and between the feedwater and cold gas of 250 - 180 = 70°. Even though the latter is a little low, heat transfer would seem possible. However, the gas drops steadily in temperature as energy is removed. The H_20 evaporates at a steady temperature of 350°F. Looking at Figure 3.1, the temperature difference at A may be insufficient or negative. Performing a more detailed analysis on the heating of the H_20 from 150° to 350° we find our suspicions confirmed.

H_20 180°F.	h_1	148 Btu/lb
120 psi sat liquid	h_f	321.8
		173.8

Energy to H_20, 1 to A = 20,615 x 173.8 = 3.582 million Btu/hr.

Gas temp at A, T_A $\quad h = h_A$
at 250°F. $\quad h = 4973.1$ Btu/mole.

$$\text{Energy from gas, A to 3} = 37.2 \times 3600\,\frac{(h_A - 4973.1)}{28.954}$$
$$= 3.582 \times 10^6$$

Solving $h_A = 5747.7$ Btu/mole.
$T_A = 818°$ R or 358°F.

That is, the temperature difference is only 8° here between the gas and the H_20. This is not sufficient and tells us that if the device were built, the flow rate of H_20 would have to be reduced to the point where the cold gas were at a temperature greater than 250°F.

If the exit gas temperature, T_3, is raised to 300°F, and h_3 is increased, the energy transferred is

$$\dot{m}\,\Delta h = 37.2\,\frac{(9785.5 - 5330.2)}{28.954}$$
$$= 20.617 \text{ million Btu/hr.}$$

This reduced energy transfer can evaporate a reduced steam flow.

$\dot{m}\,(1227.3 - 148) = 20.617$
$m = 19{,}102$ lbm/hr.

Checking the temperature difference at A, again we find $\Delta T = 58$°F. which is more satisfactory. A detailed analysis of the boiler heat transfer is necessary to see if this temperature difference will permit the required heat transfer with practical heat transfer surface areas.

With the same output as the back pressure steam cycle used as an example this cycle has slightly poorer, but still very creditable performance. Consider also that this has been accomplished without regenerative feed heating or reheat by a plant that is compact and light in weight.

Additional fuel could be burned in the gas stream to raise the temperature and generate more steam, since there is normally ample oxygen left by the gas turbine. This would increase the steam generation between two and three times depending as the turbine cycle and boiler design.

3.2 Power Recovery from Process

In the past it has been cheaper to buy electric power than to invest in on site generation, except under special circumstances (12). Present and future situations are different; subject to further change. Furthermore, the largest variable is the fuel cost which means that all possibilities require close examination. The techniques covered in previous sections are not new, nor are the principles used in power recover from processes. However, the knowledge has been the specialty of the particular industries involved.

One of the most obvious methods to produce power is by a steam power cycle. Steam produced in conjunction with a process can be generated in several ways.

(a) In boilers specifically designed to burn by-product fuels or regular boilers where by-product fuels are used as supplementary fuels.
(b) Heat recovery boilers used to extract energy from high temperature streams especially from exothermic processes.
(c) Boilers integrated into the process to recover energy and perform a process function as well (e.g. paper industry recovery boilers).

The calculations involved in boilers of type (c) are quite specific, requiring extensive knowledge of the process. These methods are widely exploited in these special fields. Calculation for boilers (a) and (b) are fairly straightforward once the important fuel characteristics (heating value: moisture content and ash properties) are known.

Heat recovery boilers (or waste heat boilers), type (b) include, and are very similar in performance to the heat recovery boiler used with the gas turbine cycle in Section 3.1. Actual cases may be complicated in design because of dust loading, and potential slagging problems, depending on the nature of the gas stream. Practical designs favour higher gas velocities, because of the lower temperature differences than in fired units, keeping in mind that dust-laden gases can cause erosion.

Steam may be available from these boilers at rates dictated by the process. This will rarely be in balance with power needs. There are several solutions.

(1) Buy power to meet the deficit. This is not likely to be satisfactory if the fluctuations in generation are severe, unless the quantity is small. Demand changes in particular, will be high and network stability could be a problem.

(2) Supply steam from fired boiler to fill in the supply valleys. This will transfer the problem from the utility company boilers to the plant boilers. If the fluctuations are not a large proportion of the steady load this may be satisfactory.

(3) Store steam during peak generation. This involves steam storage accumulators (Goldstern 13) which can supply only saturated or very slightly superheated steam. Accumulators are limited in the storage they can provide, and require capital investment.

Low pressure steam can be used for power production in a condensing turbine. For example, steam generated in a waste heat boiler at pressures not far above atmospheric, has power production potential reflecting a large fraction of available energy.

Consider 50,000 lbm/hr. steam, dry and saturated at 15 psig, saturation temperature 250°F, which can be expanded to a condenser pressure of 2" Hg. Calculating, as in the condensing section of the turbine in Section 2.5.

Expanding from 15 psig, dry and saturated; $h_1 = 1164$
$S_1 = 1.700$

at constant entropy to 2" hg $\quad h_{2s} = 950$
work per unit mass, ideal turbine $\quad$ 214 Btu/lbm

Again assuming 74% internal efficiency, actual internal work $= 160.5$ Btu/lbm.

Power output, assuming 94.8% mechanical-electrical efficiency

$$= \frac{160.5 \times .948 \times 50{,}000}{3413} = 2229 \text{ kw.}$$

This is a significant output. However, features of this turbine bear checking out. First the exhaust moisture may be high, since we used saturated steam at the inlet. To find the exhaust enthalpy

$$h_1 = 1164$$
$$h_1 - h_2 = 160.5$$

actual exhaust enthalpy, $h_2 \quad = 1003.5$ Btu/lbm.

Checking on the Mollier diagram, this corresponds at 2 inches Hg to 9% moisture which is high, but acceptable. The volume of low pressure steam can be quite surprising.

9% moisture, 2 inches Hg $\quad V_2 = 310$ ft^3/lbm

Exhaust volume flow rate $\quad = \dfrac{50000 \times 310}{3600}$

$= 4305$ ft^3/sec.

One of the significant losses of condensing machines in the kinetic energy of the exhaust. In large turbines this loss is in the range of 20 - 30 Btu/lbm (Salisbury (7)).

A small unit like this would not justify an extremely large exhaust annulus. On the other hand this loss should not be a large fraction of the work per unit mass, so that without optimizing, a value of 15 Btu or 9% of the internal work will do for our purposes.

$$KE = \frac{\overline{V}^2}{2g} = 15 \text{ Btu/lb or } 11670 \text{ ft-lbf/lbm}$$

$$V = 2 \times 64.4 \times 11670$$
$$= 866 \text{ ft/sec.}$$

Annulus area required for

$$4303 \text{ ft}^3\text{/sec. at } 866 \text{ ft/sec.} = \frac{4303}{866} = 4.97 \text{ ft}^2$$

If the hub diameter is 0.6 x tip diameter

$$4.97 = \frac{\pi}{4} D_T^2 \,(1-0.36)$$

$$D_T = 3.14 \text{ ft.}$$

This is not an enormous O.D. for a turbine, but quite large for a 2.25 MW turbine for which size high speed gear units of small diameter are popular.

Just as a condensing section can be combined with a back pressure section to provide an automatic extraction turbine this condensing or vacuum turbine can be provided with a high pressure section. This will mean that if sufficient low pressure steam is not available from the waste heat boilers, high pressure steam will be automatically admitted to make up the difference in power production. This is termed a mixed pressure turbine. It suffers from a loss similar to the automatic extraction turbine (Lyle (9)). When there is sufficient low pressure steam, the high pressure section spins idly and absorbs windage power. In fact a small flow of high pressure steam must be maintained to carry away the losses and prevent overheating.

The performance of a mixed pressure turbine is displayed on a diagram very similar to that of an automatic extraction turbine. In fact special turbines can be built that can either extract or induct low pressure steam depending on whether low pressure steam is needed for process or a surplus is available from energy recovery. A schematic performance diagram is shown in Figure 3.2.

Exothermic reactions with pressurized gas streams have recoverable energy in the tail gas. Whether recovery is feasible depends on (a) whether the gas is corrosive, dirty or otherwise unsuitable for passage through power machinery or (b) the flow and its control is compatible with the process.

Power recovery is quite effective in certain nitric acid production processes (14) where a power recovery turbine in the tail gas stream can provide a large proportion of the compressor power at normal

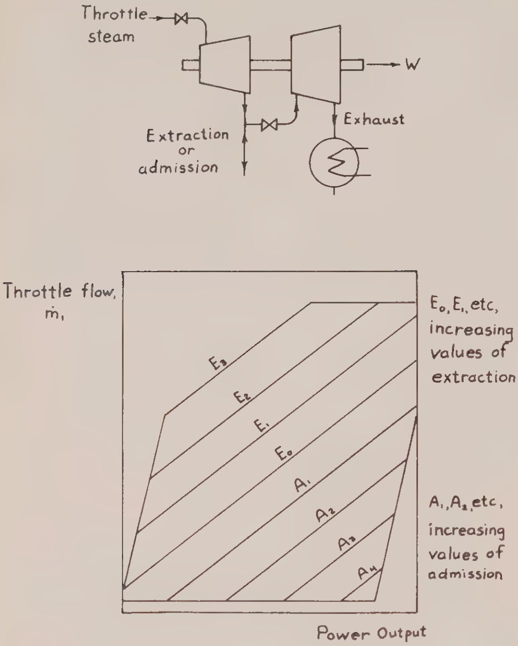


Fig. 3.2: Performance of a Mixed Pressure Turbine.

operating conditions. For example Schmid (15) describes an installation where the tail gas expander turbine provides 8000 kw of the 8500 kw driving power of the compressor. In such installations the deficit is usually made up by a steam driven helper turbine. The ammonia oxidation process for nitric acid also incorporates an integral boiler that provides steam with good power production potential.

Catalytic cracking units in petroleum refineries use large quantities of compressed air for catalyst regeneration. However in this case, power recovery is less attractive because of the lower pressure, but more importantly, the hot gas carries suspended particles which are erosive. However, about 1000°F and the gas contains carbon monoxide. A boiler integrated in the process recovers considerable energy and eliminates toxic carbon monoxide emissions.

Cryogenic processes frequently employ expansion turbines or engines in place of throttling because of more effective cooling of the product stream. The work, however, is usually dissipated in a brake for ease in control of the process.

Upgrading Thermal Energy

In Sections 2 and 3 the energy in the prime mover exhaust was at a temperature high enough for heating. In other words, although the fraction of unavailable energy was large, there was an adequate proportion of available energy to make its use attractive. A converse situation is when a process rejects energy at a lower temperature, just below the useful level ("low grade heat"). In some cases this energy can be upgraded.

Heat engines are thermodynamically capable of reverse operation, taking in work (100% available) to increase the fraction of available energy of low grade sources, resulting in thermal energy at a higher temperature. This is done for cooling (refrigeration) or upgrading of low temperature energy (heat pumps). Since mechanical or electric power are normally expensive, energy recovery by this method requires careful study in each application.

This technique involves the use of power rather than its generation and in very rough terms is an inverse process to co-generation. The thermodynamic principles are very instructive and well worth examining.

Consider an industrial process which rejects 50,000 lbm steam per hour at 180°F. This magnitude is chosen to be in the range of our previous co-generation examples.

Assuming the inlet steam to have 2% moisture, the various energy quantities can be calculated. An ideal compressor (analogous to the Rankine Turbine) compresses at constant entropy to the higher pressure. The actual compressor requires more work per unit mass of fluid. The compression efficiency is given by

$$n_c = \frac{h_{2s} - h_1}{h_2 - h_1}$$

For simplicity we will assume $n_c = 0.75$ although these compressors might do a bit better, since as we shall see they turn out to be rather large. It would be attractive to have the higher pressure steam at 300°F. (67) psia), but in case this is too ambitious, calculations are done for 250°F. (29 psia) also.

This vapour is under vacuum, but we will suppose it is pure (rather than mixed with air).

Heat pump cycles use a working fluid that boils at the low (evaporator temperature) and condenses at the higher temperature. The various refrigerant compounds come to mind. However H_2O can be used as a refrigerant in the appropriate range. If it could be used here the evaporator and condenser could be dispensed with and the low pressure steam compressed to a pressure where the saturation temperature is high enough for useful heating. The process is shown on a T-s and H-s diagram, Figure 4.1.

Trial calculations for direct thermocompression:

50 000 lbm/hr H_20 vapour, 2% moisture @ 180°F.
$H_1 = 1118.4$ Btu/lb $v_1 = 49.21$ ft^3/lbm
$s_1 = 1.7801$ Btu/lb °R

P_2 Psia	Tsat,2 °F.	ΔTsat °F.	h_{2s}	Δh_s	Work Δh	h_2	Power kw*
28.8	250	70	1220	101.6	135.4	1254	1983
67	300	120	1305	186.6	248.6	1367	3641

(*neglecting mechanical losses)

The power is nearly twice as much in the second case, so an increase of only 50° in the higher saturation

temperature has had a remarkable effect. The performance of a heat pump or thermocompression process is expressed by the Coefficient of Performance, defined

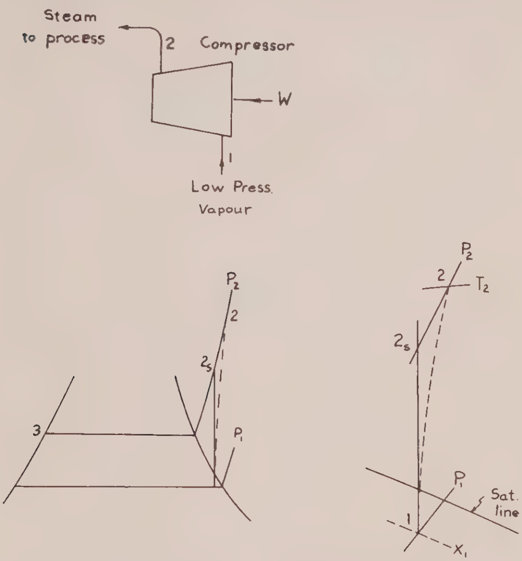


Fig. 4.1: Direct Thermocompression.

as the energy transfer at the top temperature compared to the work input. In this case it is reasonable to take the energy transfer at the top temperature as (h_2 -h_3), Figure 4.1.

$$COP = \frac{h_2 - h_3}{h_2 - h_1}$$

Repeating some of the data from above:

P_2	P_2/P_1	ΔTsat °F.	T_2	Supht °F.	COP	Inlet Cfm.	Power kw
28.8	3.84	70	435	185	7.6	41,000	1983
67	8.93	120	671	371	4.4	41,000	3641

The power requirement is rather high, comparable to the output of our gas and steam turbine in sections 2.3 and 3.1. The compressor is quite large at 41,000 cfm, larger than the compressor on the gas turbine in the example in section 3.1.

In general thermo-compression processes for H_20 should operate between saturation temperatures about 20°C. (36°F.) apart (Grossman (16)). The low molecular mass of H_20 requires several stages (probably at least seven here).

The compressors would probably require a geared drive as well. Note the superheat at the compressor discharge, which increases the work required. This could probably be reduced by interstage spray type desuperheaters. However, all these complications add up to the fact that the temperature range required here is really too great for a good solution with thermo-compression: However, where the temperature range is smaller for example in upgrading evaporator vapour for use in the coils, thermo-compression may show to advantage.

Checking the possiblity of using a heat pump cycle with a refrigerant fluid, we can see from above that the development of high superheat in the compressor is a disadvantage. Furthermore the fluid should have a critical temperature well above the upper saturation temperature. This requirement surprisingly limits the choice of fluids. R113 is one possibility, another is Fluorinol 45 (See the list of General References and Reference 21). Desirable features would be lower power requirements and smaller inlet volume flows.

	T_1 °F.	$T_{sat\ 2}$ °F.	h_1	h_{2s}	Δh_s	Δh
R113	165	265	103	110.6	6.88	9.17
F45	165	265	390	430	40	53.3

	$h_f{}'$ P_2	h_1-h_f	m lbm/hr	Power KW	Inlet Cfm	COP
R113	63.2	40	1.213x10^6	3259	20,236	5.41
F45	139	251	193,306	3018	38,339	5.70

Compressors, n_c = 0.75,

Q_{input} = 48.52 million Btu/hr

The use of a heat pump cycle with a separate working fluid has not improved the situation, except for the smaller compressor with R113. The lesson is clear. Heat pumps and thermocompression are effective where the temperature range is as small as possible.

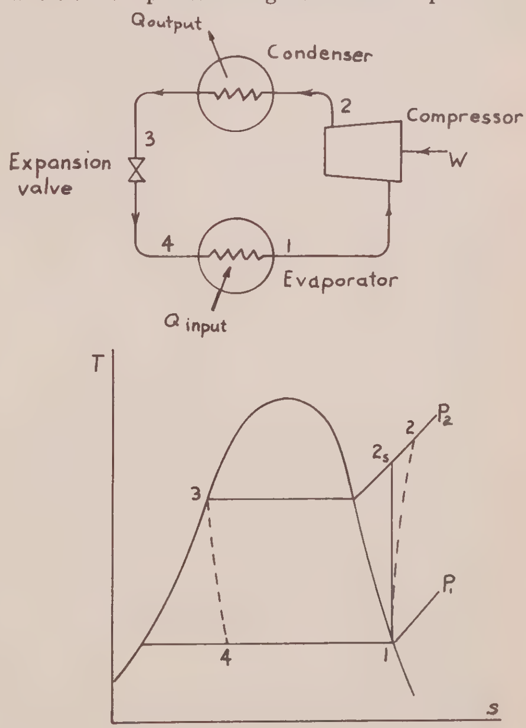


Fig. 4.2: Vapour Compression Heat Recovery Cycle.

Special Working Fluids

5.1 Power cycle fluids

H_20 (both water and steam) is the standard working fluid for vapour power cycles, and air or combustion products for gas power cycles. This is hardly surprising because water and air are plentiful and non-toxic. Other fluids would have to demonstrate clear advantages to be chosen, but for specialized service other fluids such as the various refrigerants are preferred.

The Second Law of Thermodynamics states that in the rather specialized situation where heat is supplied at a given constant hot temperature and rejected at another constant low temperature, all reversible heat engines will have the same (and maximum) efficiency, independent of the working fluid. Actual power and heat pump cycles involve irreversible elements such as heat transfer through a temperature difference, throttling and irreversible compression or expansion. Special working fluids may offer advantages in performance in these situations. Also H_20 has some practical disadvantages:

- High pressure (and resultant material stresses) at high saturation temperature.
- Development of moisture in the steam during the expansion process.
- Very large specific volume of vapour at low pressures, requiring huge exhaust areas for large outputs.
- Sub-atmosphere condenser pressures.

The first three disadvantages are more significant with large units (say 350 MW and up) which are not typical of industrial generating units.

As a result, the use of special fluid in industrial vapour power is more restricted. Perhaps low temperature waste gas streams can be exploited for power production. Shepherd (17) analyzes the performance of isobutane, Refrigerant 21 and Fluorinol 85 for power recovery with top temperatures of 450°F., 400°F., 350°F. and 300°F. and several condensing temperatures. A source of energy investigated was hot geothermal water. Horn and Norris (18) have studied a series of fluids for "bottoming" cycles for large generating station units to reduce the large size of the low pressure elements of large steam turbines - a similar application to power recovery from low temperature sources. In a bottoming cycle, the reduction of capital cost in reduced exhaust annulus area, number of stages and leaving loss must balance the loss due to heat transfer to the second fluid. Considering thermal properties, cost, flammability and toxicity, Horn and Norris found R-21 (Dichloromonofluoro methane) the most suitable. Before considering the complication of a special fluid for an industrial cycle, it would be necessary to prove that the steam turbine was so large and expensive that a size reduction by using a special fluid would be really attractive.

5.2 Heat Transfer Fluids

Where it is desired to transport thermal energy by a fluid without phase change it is necessary to pressurize the fluid. With water fairly high pressures are needed if the temperature is high, as in nuclear reactor cores. A solution here is a suitable heat transport fluid with a lower vapour pressure. Unfortunately water posseses thermal properties that are hard to match and other fluids require greater mass flows. However, very successful applications of these fluids have been made.

The use of heat transport fluids may simplify energy recovery from hot gas waste streams. Most users would not wish to use hydrocarbon fluids for this purpose because of flammability, but in industries where hydrocarbons are processed in fired heaters, these fluids are accepted.

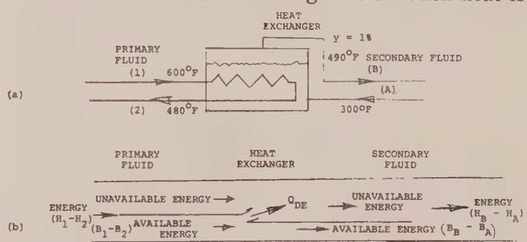
Second Law Efficiencies

There are about as many definitions of efficiency as there are devices to which they refer. Some give the ratio of the energy out of the device in the form desired to the energy into the devices that has to be paid for. Others compare the output of the device to the output of a perfect device. Because of the conservation of energy the ratio of energy out to the energy in is always 100%; this does not give any information about the performance of the device. However, the ratio of the available energy out to the available energy into the device, is less than 100% and its value is a measure of the performance of the device. It should be noted again that available means available to do work.

6.1 Heat Exhangers

A device which handles energy is the heat exchanger in which energy in the form of heat is taken from a hot fluid and given to a cold fluid. The main heat exchanger in a nuclear power plant is an example. For illustration consider a power plant where the reactor adds 1000 MW of energy to the primary fluid raising its temperature from 480°F (249°C) to 600°F (315.5°C), as it flows through the reactor. Of the 1000 MW, 460 MW are available energy. The 1000 MW are carried by the primary fluid to the main heat exchanger where it is transferred to the secondary fluid. However on heat transfer some of the avaiable energy becomes unavailable and even through 1000 MW leave the heat exchanger with the secondary fluid only 416.5 MW are available while 583.5 are unavailable. The second law efficiency or effectiveness ϵ of the heat exchanger is the ratio of 416.5 to 460 or 90.5%. .

It seems worthwhile to explain how the above figures are obtained. Please refer to Figure 6.1. When heat is



Q_{DE} ≡ Energy degraded from available to unavailable in heat exchanger

Fig.6.1: Main Heat Exchanger of a Nuclear Power Plant. (a) Physical Layout, (b) Energy Flow.

taken from the primary at 600°F. the fraction of this heat which is available is given by the efficiency of a Carnot engine receiving heat at this temperature and rejecting heat at 80°F. As the primary cools, the efficiency of the Carnot cycle which could receive heat from it is reduced; a greater fraction of the heat taken from the primary is unavailable. It is more convenient to determine the unavailable part Q_R than the available part Q_A. The former is

$$Q_R = \int T_o \frac{dQ}{T} = T_o \int dS = T_o (S_1 - S_2)$$

S = Entropy

T_o = Lowest temperature at which heat can be rejected.

The total heat Q taken from the primary in the heat exchanger or the thermal power of the reactor (neglecting power of primary pumps) is given by

$$Q = H_1 - H_2 = 1000 \text{ MW}$$

The available part of the heat taken from the primary is the difference

$$\begin{aligned} Q_A &= Q - Q_R \\ &= (H_1 - H_2) - T_o (S_1 - S_2) \\ &= (H_1 - T_o S_1) - (H_2 - T_o S_2) \\ &= B_1 - B_2 \text{ where } B = T_o S \text{ (Flow Availability)} \\ &\qquad \text{(Haywood 1974) (19)} \\ &= 460 \text{ MW} \end{aligned}$$

It should be noted that Figure 6.1 (b) does not show the flow of energy in the pipes for example at point (1) but the net energy flow from the reactor to the heat exchanger or into the heat exchanger which is $(H_1 - H_2)$ and the net available energy flow into the heat exchanger which is $(B_1 - B_2)$.

The secondary fluid carries energy Q from the heat exchanger:

$$Q = H_B - H_A = 1000 \text{ MW}$$

Conservation of energy dictates that this equals $(H_1 - H_2)$. However, heat taken from the primary is given to the secondary at a lower temperature and when it enters the secondary a larger part is unavailable than when it left the primary, i.e.

$$T_o (S_B - S_A) > T_o (S_1 - S_2)$$

which indicates that

$$(B_B - B_A) < (B_1 - B_2)$$

In other words, available energy is degraded into unavailable energy in the heat exchanger. Energy is conserved; available energy is not.

$$B_B - B_A = 416.5 \text{ MW}.$$

The second law efficiency or effectiveness of the heat exchanger ε is given by

$$\varepsilon = \frac{\text{Available Energy added to secondary}}{\text{Available Energy taken from primary}}$$

$$= \frac{B_B - B_A}{B_1 - B_2} = \frac{416.5}{460} = 90.5\%$$

Various names are given to the available energy degraded to unavailable energy, for example: irreversibility, dissipation, loss of available energy, lost work and exergy consumed.

6.2 American Physical Society Method

The American Physical Society in AIP Conference Proceedings No. 25 of 1970 (Physics 1975) (3) has proposed a method of measuring performance which is sometimes called effectiveness and which they call second-law efficiency, ε. The esence of this method is that

$$\varepsilon = \frac{\text{Available Energy in output}}{\text{Available Energy in Input}}$$

This method is illustrated by the following examples:

(1) *House heating with an oil furnace.* The enthalpy of combustion of the fuel $(-\Delta H)$ is taken as the available energy in the input. This is based on the premise that in a perfect and ideal fuel cell all the energy taken from the fuel is available. The heat given to the house is $n(-\Delta H)$ where n is the normal or first law efficiency. Only part of this heat is available; the available part is $n(-\Delta H)\left[\frac{T_s - T_o}{T_s}\right]$ where T_s is the temperature at which the heat is supplied to the house and T_o is the temperature of the atmosphere. This energy is the work output of a Carnot engine receiving an amount of heat, $n(-\Delta H)$, at temperature T_s and rejecting heat at T_o. These two quantities give

$$\varepsilon = \frac{\text{Available part of heat to house}}{\text{Available energy in fuel}}$$

$$= n\left[\frac{T_s - T_o}{T_o}\right]$$

With a first law efficiency of 60% a supply temperature to the house of 110°F. and an environment temperature of 32°F. this gives $\varepsilon = 8.2\%$.

(2) *Electricity generation from fossil fuels.* The available energy input is again considered the enthalpy of combustion $(-\Delta H)$ and, as the electricty is all available, the available energy in the output is the electrical energy produced.

$$\varepsilon = \frac{\text{Electrical energy produced}}{\text{Enthalpy of combustion of the fuel}}$$

This is the same as the normal or 1st law efficiency of a fossil-fuelled electric generating station.

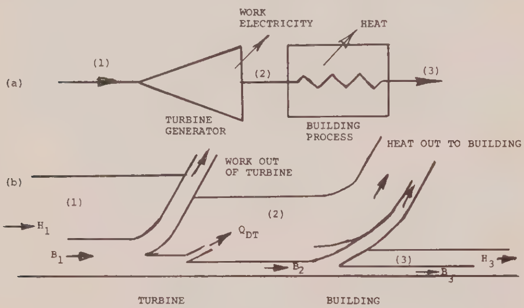
Thermodynamic theory indicates that in a perfect and ideal fuel cell, the electric output and $(-\Delta B)$ are within 10% or 20% of the enthalpy of combustion $(-\Delta H)$. However, no practical fuel cells (perfect or imperfect) have as yet been developed which use carbon or hydrocarbon fuels. Most always when fossil fuels are used they are burned in air or oxygen and the energy in them is thereby converted to thermal type energy. Immediately after combustion the availability is only about 70% of its value before combustion. As well some of the available energy in the products of combus-

tion goes out the exhaust or up the stack in all practical cases. It does not seem reasonable to compare actual processes with a process which is so far from attainment; it might be better to consider the available energy of the input to be the availability of the products of combustion at the theoretical flame temperature following combustion.

This conference proceedings also suggest the use of a non-flow rather than a flow availabilaity and a contribution to availability from diffusion work. These differences are not considered important enough in cogeneration to be considered at this time.

6.3 Apportioning Costs with Cogeneration

Forty six years ago Professor Keenan (Keenan 1932) (2) suggested that when steam is used for both production of electricity and then for heating buildings, the party producing the electricity be charged for the availability decrease of the steam in the production of electricity (B_1 - B_2) and the party heating the buildings be charged only for the availability decrease of the steam in that process (B_2 - B_3). See Figure 6.2. In other words charges should be based not on energy used but on available energy used. As Fig. 6.2 indicates, the flows of energy and available energy refer to a single stream of fluid.



Work out of Turbine = H_1 - H_2

Decrease of Availability in Turbine = B_1 - B_2

= (Work out) + Q_{DT}

Q_{DT} = Energy in steam degraded from available to unavailable while in turbine

Heat out to Building Heating = H_2 - H_3

Decrease in Availability in Process of Heating Building = B_2 - B_3

Fig. 6.2: Energy and Availability Flow with Steam Which is Used for Electricity Production and in Process Heating. (a) Physical Layout, (b) Energy and Availability Flow.

The above method has a defect; the producer of electricity requires only available energy whereas the consumer of heat requires unavailable energy along with the available energy. It might be argued that this latter party could obtain his unavailable energy from the atmosphere without charge but this is not completely true; the equipment required (heat pump) is costly.

When there is a large demand for heat, electricity is considered a by-product and is charged for only the additional costs entailed by its production. As the demand for electricity increases it is considered a co-product and bears a share of the common costs. On the other hand electricity may be the main product and heat the by-product. In this case the heating or process should be charged with only those additional costs which are directly attributed to it.

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Discussion:

Old and New Developments in Cogeneration

PROFESSOR J. D. McGEACHY,

Queen's University

Question: Gaston Boucher, *Hydro Quebec*

If, instead of throttling the steam at the intake of the turbine, you put a variable speed drive on the water pump to the boiler and then you throttle the fuel going to the boiler, you lose less efficiency.

Answer: Prof. McGeachy

You would, in that case, vary the boiler pressure. I'd like to go a different way even from that. This would mean that we would have variable speed feed pump which, from a thermodynamic point of view, is always excellent, though from a maintenance and capital cost point of view, we might not like it. We could vary the boiler pressure, this would vary the pressure going into the turbine and would automatically vary the mass flow. We could keep our initial temperature up. Now, this would involve making sure that the heat transfer margins in the super heater were always safe to control the metal temperatures. It would be expensive. I doubt if we could justify it in small units economically, although it's well worth studying. Several large central generating station cycles operate this way now, and it avoids the degradation of available energy from the throttling or even the partial throttling that is involved with nozzle control on ordinary turbines, and is very definitely headed in the right direction. It's a question of whether we can afford it in small sizes.

Capital Cost Associated with Cogeneration in the Pulp and Paper Industry

W. M. NEWBY
Canadian Boiler Society

The relatively low heat rate for power generated in a non-condensing steam turbine through which steam is passed to a process often justifies examination of the economics of power generation in industries requiring substantial amounts of heat at low steam conditions, such as the pulp and paper industry. Capital cost is a major factor in such an examination. In general, most steam plants, in which on-site power generation is practical, fall into one of three main categories. This paper presents capital cost details of an example in the pulp and paper industry for two of these three categories.

Capital costs Associated with Industrial On-Site Generation of Electricity in the Pulp and Paper Industry

The relatively low heat rate for power generated in a non-condensing steam turbine generator through which steam is passed to a process justifies examination of the economics of the generation of electricity in industries requiring substantial amounts of heat at low steam conditions such as the pulp and paper industry. Capital cost is a major factor in such an examination.

In general, steam plants in the industry fall into three main categories, and this paper presents capital cost details for one example in each of the first two:

1. Those producing steam at low pressure as required for the process, but with some or all boilers designed for high pressure operation. (Example "A")
2. Those producing steam at high pressure in some or all boilers, with or without facilities for the generation of electricity. (Example "B")
3. Those producing steam at low pressure as required for the process, in boilers designed for only low pressure.

Most modern plants fall into the first two categories, although considerable potential for the generation of electricity exists in older mills in the third category. In any event, the basic factors to be considered are reasonably similar for the three categories.

For plants in Category 1, the costs chargeable to the generation of electricity can include:

— installation of superheaters, or modifications to existing superheaters, in the boilers designed for high pressure operation, and possibly the installation of additional heat recovery surface, usually in the form of economizers,

— replacement of boiler feed pumps, or installation of high pressure pumps,

— installation of the turbine generator with its associated equipment such as a crane and oil purifier, and piping systems such as oil and air cooling piping,

— replacement of low pressure piping systems such as boiler leads and feedwater supply lines, and the installation of high pressure piping to the turbine as well as exhaust and extraction piping from the machine to the distribution systems,

— installation of equipment to improve the quality of the boiler feedwater,

— installation of electrical equipment and systems required for the generator and its connection to the existing system,

— construction of building, and foundations for equipment.

An additional cost chargeable to the generation of electricity can be incurred through curtailment of mill operation owing to removal of equipment from service for conversion modifications. This can be reduced or prevented in some cases by careful design and scheduling, but in other cases, the temporary installation of rental packaged boilers may be justified.

There are cases in which even the use of rental boilers to maintain mill operation is not practical. Until twenty five years ago or so, it was not unusual for steam plants to carry spare boiler capacity which would permit shutting down one unit for at least the summer period, and in some cases, during the winter as well. The practice of carrying spare capacity is not common now, and a modern pulp mill requiring up to a million pounds of steam per hour may have only two boilers, a power boiler and a recovery boiler. The power boiler may be of such a capacity that replacement with tem-

porary packaged boilers is not practical, and in the case of a recovery boiler, a mill cannot operate without the chemical recovery function of the unit. In the light of current uncertainties concerning future power costs, these factors can provide incentive for constructing and operating a plant at high pressure even though the generation of electricity may not be attractive at the time.

Where boilers are already operating at high pressure as in Category 2, costs are required for only those items directly involved in the generation of electricity such as the turbine generator with its associated mechanical and electrical equipment and systems and structure.

Where no new boilers are required for plants in Category 3 for reasons of replacement of existing equipment and/or an increase in the process heat demand, the possibility of justifying new boilers on the basis of only the economics of the generation of electricity is generally quite remote. A troublesome problem in the economic analysis in such a case is the preparation of a realistic estimate of the life of existing boilers since the life of properly maintained units can be almost unlimited.

The capital cost required for economic analysis where new units are required in any plant is the incremental cost obtained by subracting the cost of a low pressure boiler installation to supply steam at the conditions required for the process from the cost of a high pressure installation with electrical generation facilities. Under current conditions, serious consideration should be given to the design of any new boiler of appreciable size for conversion to higher steam conditions even though the generation of electricity should not be attractive at the time, and high pressure operation is not justified onthe basis of other considerations.

Example "A", Category 1

The industry in this example is a newsprint mill in the Maritimes. The installation of additional steam generating capacity was not anticipated, and the cost estimate was intended to be of a degree of accuracy only as required to permit a decision concerning the justification for a more detailed study. The estimate is shown in Table I and was prepared in 1974. As noted in the table, the items identified by asterisks are based on budget estimates submitted by manufacturers and the cost so obtained is about half the total. The balance of the items were estimated by the consultant on the basis of experience and comparison with other installations.

The arrangement is unusual in that only part of the mill steam demand is met by its own boiler plant on the site. The additional steam required is provided by the provincial utility from a thermal station immediately adjacent to the mill. In the station, the steam is generated at 1250 psig, 950 F, passed through a non-condensing turbine generator and discharged to the mill at the pressure required by the paper machines, 60 psig. The mill's steam plant consists of one boiler fueled by oil and mill refuse including clarifier sludge.

The mill's boiler operates at steam conditions of 300 psig saturated, but is designed for conversion to conditions of 1250 psig, 950 F. At present, the steam is reduced in the plant to 60 psig. The operating pressure of 300 psig may appear to be unreasonably high in the light of the low pressure required by the process, but this represents the boiler designer's selection of the most reasonable compromise between two conflicting requirements. On the one hand, the steam drum diameter must be great enough to ensure dry steam at the low pressure, but the larger the drum, the thicker the plate required. In this particular case, the drum plate in the convection tube area is about 7" thick which is unusual for an industrial boiler of this capacity.

The boiler has a capacity of 240,000 lb/hr on oil alone, or on oil and refuse. On refuse alone, the unit can generate about 110,000 lb/hr. At the full-flow design conditions the turbine generator would have a terminal output of 17,700 kw.

The estimated cost does not include an allowance for curtailment of mill operation during shutdown for conversion, nor the cost of a temporary packaged boiler installation as these could be established only by a more detailed study.

An alternative which might be attractive, but which was not investigated in detail at the time of the study, is the installation of the new turbine generator in the utility station with the high pressure steam supplied through a pipe line from the mill's boiler plant. A further refinement would be to consider the installation of the necessary demineralizing equipment in the utility station with the water pumped to the mill's plant through stainless steel piping. These alternatives might offer savings in operating and maintenance costs since the station might be able to provide the necessary service with minimal staff increase. In addition, some savings in the cost of the electrical systems could be expected.

A complication not dealt with in the preliminary cost study is presented by the fact that the boiler and turbine generator in the utility station are actually the property of the mill, and a more detailed study would have to consider the installation of a smaller turbine generator with a steam capacity equal to only the steam flow from the boiler on the mill site. In this case, the cost per installed kilowatt could be expected to be higher than shown in Table I.

Example "B", Category 2

The industry in this example is a kraft mill in northern Ontario, and is integrated with a stud mill. A new boiler and a turbine generator were installed in 1974 and 1975, and costs are shown in Table II. The owner maintained an effective system for controlling and recording the costs. In some cases, such as the structural work and some piping systems, a split between steam plant costs and power generation costs had to be somewhat arbitrary since it was not considered justified to set up design, drafting and purchasing procedures to permit an accurate split. In addition, of

course, the incremental costs over and above a low pressure installation shown in the table are only estimated. In any event, the degree of accuracy of the total cost can be considered relatively high.

Table I

CAPITAL COSTS FOR EXAMPLE "A" (CATEGORY 1)

Boiler superheater and economizer	$ 500,000*
Turbine generator	1,300,000*
Piping	400,000
Instruments and controls	10,000
Boiler feed pumps	85,000*
Feedwater treating system	300,000*
Pressure reducing valves and desuperheaters	35,000*
Turbine room crane	30,000
Building	300,000
Electrical work	400,000
Spare parts	40,000
Engineering and miscellaneous charges	600,000
	$4,000,000

Capital cost per kilowatt - $226

* Costs based on manufacturers' estimates

Table II

CAPITAL COSTS FOR EXAMPLE "B" (CATEGORY 2)

Actual project costs:	
Turbine generator	$1,115,000
Piping	180,000
High pressure feedwater heater	32,000
Turbine room crane	26,000
Building	260,000
Electrical work in kraft mill	395,000
Electrical work in newsprint division	330,000
Spare parts	35,000
Engineering and miscellaneous charges	280,000
Total project costs	**$2,653,000**
Est. increm. costs over 155 psig installation	**600,000**
Total cost chargeable to gen. of electricity	**$3,253,000**

Capital cost per kilowatt - $217

Before installation of the new boiler, the mill steam demand was met by the following:

— one chemical recovery boiler installed in 1965 with a capacity of 200,000 lb/hr of steam at 625 psig, 725 F,

— four power boilers with ages ranging from forty to sixty years and with a total capacity of about 100,000 lb/hr of steam at 155 psig, 435 F. The oldest boiler was capable of burning a small percentage of the mill refuse. These units are in a plant located remote from the recovery boiler plant.

The recovery boiler has been operating at its design steam conditions since its installation, even though no electrical generating equipment was installed, in anticipation of future generation and to permit such installation at minimum cost. Some of the high pressure steam was put to useful work through a number of mechanical drive turbines including one for the induced draft fan, a particularly appropriate application in the case of a recovery boiler under such conditions.

The new boiler and turbine generator were justified on the basis of a number of considerations including the following:

— the returns offered by burning all the mill refuse thus displacing primary fossil fuel,

— the returns offered by the lower heat rate for the generation of electricity,

— the improvement in efficiency offered by the new boiler,

— the necessity to dispose of the mill refuse in a manner acceptable to the environmental control authorities,

— the elimination of production losses due to limited steam capacity during some winter months,

— an increase in steam demand by the stud mill.

It should be noted that while all the above factors would seem to result in an economically attractive installation, the complete project was barely justifiable, and only a result of the abundance of low cost fuel in the form of refuse from the pulp and stud mills, and the need to resolve the problem of disposing of this refuse.

The new boiler has a capacity of 170,000 lb/hr of steam at 625 psig, 750 F on natural gas alone or on gas and refuse. On refuse alone, the unit can generate 110,000 lb/hr. The boiler is designed for replacement of natural gas as the primary fuel with oil or coal, and the plant was laid out accordingly. Coal bunkers were not installed, but the building steel and foundations were designed so that they could be installed.

The turbine generator is rated at 15,000 kw, and the unit is non-condensing, exhausting at 55 psig and with automatic extraction at 155 psig. The studies indicated that a unit with a rating of 12,500 kw would be adequate for the anticipated conditions, but quotations received when purchase of equipment was in progress revealed that the larger unit could be purchased at a relatively small extra cost owing to the fact that it would be almost identical to one furnished to another pulp mill some years earlier. The extra cost was considered justified to provide a margin for possible future changes in the process, and at this time the mill is reviewing a number of its activities to assess the practicality of dropping the steam pressure from 155 psig to 55 psig in order to generate more power.

Figures 1 and 2 show the systems before and after. Relatively little auxiliary equipment was required for the new plant. Of the major items, the existing deaerator required only minor modifications, one new high pressure boiler feed pump was installed, and an additional control valve added to the 600/155 psig steam pressure reducing station. Tie-in connections, both mechanical and electrical were made during normal mill shutdown periods so that no unscheduled loss of product of any significant magnitude was experienced during installation and start up of the new equipment.

The plant presented some interesting control problems. During the winter the situation is fairly straightforward in that some primary fuel has to be burned with the refuse in the new boiler, and this fuel can be automatically varied to maintain constant the

pressure of the 600-psig header. In the summer, however, the refuse available from the mill results at times in an excess of steam generated over and above the mill demand, and adequate storage for this condition would not be practical. A condenser on the turbine was not considered to be justified, but instead, excess steam is vented from the 55-psig system to a condenser at atmospheric pressure, and the heat is reclaimed by using some of the process water supply as cooling

FIG. 1
Example "B"
BEFORE GENERATION OF ELECTRICITY

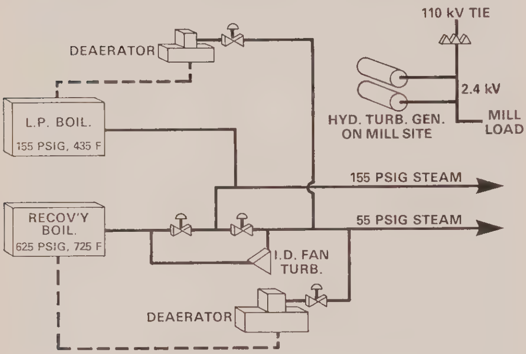
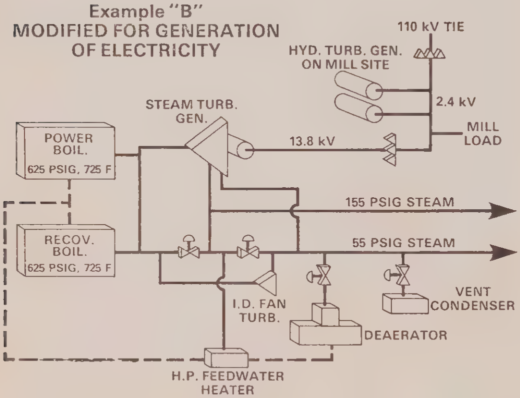


FIG. 2
Example "B"
MODIFIED FOR GENERATION
OF ELECTRICITY



water in the condenser. The major control problem arose from the fact that during the summer, when steam is vented to the condenser, all fuels, i.e., the black liquor to the recovery boiler and refuse to the power boiler are manually controlled so that the pressure of the main steam header has to be controlled by automatically varying the rate of steam vented to the condenser. The rate of feed of the refuse can thus be varied manually to suit the rate of its supply and the limits of the storage and feeding systems. In other words, if it should be necessary to increase the rate of feed of refuse, the resulting increase in the main steam header pressure will open the vent valve wider to keep the header pressure at its set level.

The electric power situation also introduced a problem. The mill is integrated electrically with two hydraulic generators on the mill site, a number of remote hydraulic generating stations owned by the company, a newsprint division of the company, and finally, Ontario Hydro. Prior to the installation of the turbine generator, power was imported into the mill through the tie line. The generation of additional power on the site resulted in the export of power, and as this would be transferred to the newsprint division, modifications were required to the electrical systems in that division. The cost of this work is shown in the table.

The turbine is normally operated with all process steam passing through the machine, and the turbine controls maintain the extraction and exhaust pressures constant, with the turbine speed controlled by parallel operation with the system. In the event of loss of the system tie, solenoid valves in the turbine control systems interlocked with the tie-line switchgear operate to switch the turbine to speed control. Under these conditions, the load on the mill generating equipment is sharply reduced. When on back-pressure control, with the speed element out of service, the action of the controls is such that, on a switch-over to speed control, the governing system would "see" a demand for maximum speed, and there was some concern over the possiblity of instability resulting from interaction with the governors on the hydraulic generators on the mill site. The standard controls on the steam turbine were modified to permit the operator to preset the controls so that on switch-gear, the governor "sees" the speed corresponding to the estimated demand at that time. The turbine steam control valves are thus immediately positioned to suit that load, and subsequent trimming adjustments are of small magnitude.

Conclusions

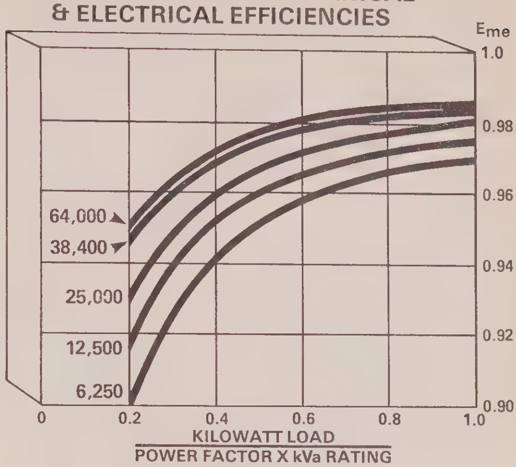
The costs per installed kilowatt in the two examples considered were \$226 and \$217, and these are reasonably typical for the time they were applicable, i.e., 1974 and 1975. At that time the costs per installed kilowatt for utilities were about \$412 - \$690 for hydro-electric plants, \$308 - \$375 for fossil fuel fired plants and \$680 - \$760 for nuclear plants, and these costs would have been about \$330 higher if transmission costs were added. Capital costs for transmission systems do not generally apply in the case of industrial on-site generation of electricity. It should be noted that the unit costs per kilowatt are not entirely comparable in that the utilization factor for an industrial turbine generator (the ratio of the maximum demand to the rated capacity) may be lower depending upon the margin allowed in the design for future increases in steam flow. In addition, the annual load factor may be lower owing to seasonal variations in steam demand. Even allowing for such factors, however, the difference in costs is dramatic, and a comparable difference exists at the present time.

Such a comparison of costs might be expected to arouse some curiosity as to why more mills in Ontario are not equipped to generate electricity. To a major extent, the answer lies in the fact that, even though the

heat rate is less than half that for a central station, capital expenditures in a mill are made on the basis of relative returns on the money spent, and in Ontario and Quebec, in particular, the returns on equipment to generate electricity are generally not attractive except possibly in cases where cheap fuel such as wood refuse are available in abundance.

In the light of the fact that industry and the public pay for new generating facilities, and the fact that reductions in fuel consumption must be achieved, it would seem highly desirable to investigate means by which public funds may be made available to assist in the development of all practical potential for industrial generation of electricity. In addition, consideration should be given to the practicality of making available to mills in the vicinity of fossil fuel fired central stations fuels for generation of electricity which the utilities can obtain at lower cost by virtue of purchase and delivery in large quantities.

TYPICAL APPROX. MECHANICAL & ELECTRICAL EFFICIENCIES



(DATA: GENERAL ELECTRIC CO.)

Discussion:

Capital Costs Associated with Cogeneration in the Pulp & Paper Industry

W. M. NEWBY, *W. M. Newby and Associates Ltd.*

Question: Gerry Lewarne, *Morris Wayman Ltd.*

Mr. Newby, you mentioned the problem that you had in the summer producing too much steam and the proper amount of the other thing.

Answer: Mr. Newby

The question of the excess stain from the refuse and . . .?

Question: Mr. Lewarne

Yes. If you had put in a boiler which had higher steam conditions could you not have solved that problem generating the proper balance?

Answer: Mr. Newby

It could be. The only problem would be that I think it would be a bit of a mess with a two boiler plant and having one operate at 1200 and the other one at 600. I think it would get a bit sloppy. The piping costs would go up and you would need a complete new batch of feed pumps. I don't know. It was considered, I think, that life would be an awful lot simpler if it were just kept at the same pressure. This wasn't done. It wasn't checked out and nobody could work up any enthusiasm for spending any time on it at all. It just seemed to be unnatural. (See discussion on Paper #13.)

Question: Gaston Boucher, *Hydro Quebec*

You pointed out to your audience that lots of people buy new boilers for high pressure or future high pressure. But, from what the professor here said, don't forget that the turbine needs two things. It needs the high pressure and the high temperature, otherwise you have condensation in the last stages of your turbine. Now, when you buy a boiler for high pressure alone, with the addition of this super heater after that requires almost the price of a new boiler and we met this condition in a mill that we were studying. They were all equipped for a thousand pounds, but when we came we said you need 850°F. Well, they asked for $1,750,000 to modify the boiler where it had been paid $1,700,000 five years before. And then what really killed it, is when they said it would take eight weeks to modify the boiler. Well, paper mills do not even want to shut for eight hours. You can imagine eight weeks! And I think you should tell your audience that they need to buy both the provisions for high temperature and high pressure and operate with pressure and temperature reducing valves as need be.

Answer: Mr. Newby

You were very gentle on me. Thank you. You are right and partly this comes about through the sloppiness of my terminology and that I kept referring to high pressure because it was easier to say "high pressure" than "high pressure and temperature." A lot of units, of course, if you are buying one for low pressure and arranging for it to be converted in the future, you do of course have to make your mind up at that time what the future temperature is going to be. But, you don't necessarily have to put in the super heater at the start. So, it becomes somewhat of an academic question as long as you do tell the designer what the upper limit is going to be. A lot of

mills can operate, and do operate, on saturated steam. Consolidated Bathurst and the older mills are all saturated steam and that's really no problem. Some of the Price mills are too. And you are quite correct on the cost of installing the additional super heater as a matter of interest in that Table 1, and this was obtained from the supplier, it was about a half million dollars to install the super heater and economizer, both of which would be required. But, the other angle is, as you point out, the down time you just can't tolerate. In the case of Example A, I think that probably it would be economical to use a rental boiler to keep them on the line until it is done and that gives you lots of time. This was done by Fraser companies in Edmundston, New Brunswick back when we were involved in converting them from coal to oil. When you think of it, it was a most unfortunate decision, wasn't it? Anyway, in the course of it, they did decide they needed a temporary boiler ($125,000) and it worked out very well. It doesn't cost much to install. But as you say, there are limitations as to how high you can go.

Question: Ken Voss, *Ontario Paper - Thorold*

I have some comments that I would like to make. We've been operating extraction turbines at our newsprint mill in Thorold since 1934, making about 11 megs, with absolutely a minimum of maintenance problems on two old GE turbines which are still rolling along very satisfactorily. We are having a great look at the possibility of generating steam and electric power from municipal refuse and, in this context, I have talked to the Hooker people in Niagara Falls, N.Y. who are going ahead with the project to burn 3,000 tons of garbage a day to produce 600,000 pounds of steam an hour. Their concept of this problem of a steady steam load versus a steady power load - they are putting in turbines that will go from 100% extraction to 100% condensation depending on the process steam requirements. But, my main purpose in getting up is to comment on the speakers' views about the difficulties of raising capital to finance these projects we are discussing and contemplating. The Hooker project is almost 100% financed through the sale of revenue bonds by the New York County Industrial Development Authority. and this consortium of bankers and so on, are empowered to finance this type of industrial development through the sale of these tax exempt bonds, which of course are very attractive. I would urge that all of us urge our governments to have a similar look at this type of financing.

Answer: Mr. Newby

Thank you, Mr. Voss. I think that is a very appropriate point. I've been hoping for a long time that you guys in Thorold would proceed with that refuse disposal system because I think that's the way it's got to go. I think we all should look forward with a great deal of interest to seeing that one in Niagara Falls, N.Y. take off, because it will be a spectacular showpiece, I think. And, there are so many like that too. In St. John there is Rossi right in the middle of the city. It would be a cinch to apply it there. surely this is the way it's got to go. Thank you.

Question: Gordon Robb, *Department of Energy, Mines and Resources*

Bill's first example sounds very much like the New Brunswick Power Commission Courtney Bay situation and that is a very interesting story in terms of financing cogeneration. The New Brunswick Power Corporation have an oil-fired generating station in St. John, New Brunswick and some years ago it was decided to build a newsprint mill adjacent to that power plant, and the New Brunswick Power Commission agreed to sort of be an engine of industrial development and they installed a non-condensing turbine unit in the Courtney Bay plant, so that the financing was strictly utility financing. The electrical capacity was cheap capacity as compared to condensing capacity, and the corporation had to supply the electrical energy in any case. In that case, they also financed the boiler so that financing the newsprint mill was easier. That arrangement worked out very well. It hasn't caused any real problem for the Power Commission. Some years later, it was decided to put in the second newsprint machine and it was decided at that time that bark had to be burned. The bark from the wood for the first newsprint machine had just accumulated, I think it is still there. But, unfortunately, the Industry-Utility cooperation didn't work quite so well the second time, and the mill built a bark boiler which is the boiler that Bill described. There was a lot of talk about burning the bark in the utility power plant, but at that time utilities weren't interested in burning bark so the situation which now prevails there,developed. It now appears that you could get some cheap capacity by installing the turbine that Bill was talking about, either at the mill or in the power plant. but I think the main point is here's an example where this problem brought about by the fact that utilities sell at a rate based on average costs, whereas the industry is looking at today's inflated costs if it owns the cogeneration system, and generally, utilities don't look at this opportunity to get some cheap capacity on the overall system by owning the cogeneration system, at least the turbine generator part of it.

I'm going to ask a question, though. Bill, you gave figures for 1976/77 (1974/75) for this increment for the turbine generator in the Case 1 of $220 per kilo? What would that be in today's . . .?

Answer: Mr. Newby

The only feedback I got is, just recently I went through an exercise with a company and by checking with the various suppliers we were given to understand that from 1974/1975, that period to 1979, that the multiplying factor could be in the order of 1.5 to 1.6 for most equipment. In the case of piping, as I say where the unions are a little bit more active and stronger, then the factor would be double. So presumably you'd be talking about something over

$300 per kilowatt ($300 - $350) which I think checked with what somebody produced yesterday. It gave me some confidence. But, thanks for your comment on the other and you are quite right, of course, this is MacMillan Rossi and N.B. Power, and of course the other example is Abitibi in Smooth Rock, Ontario. I did check with both of them and they agreed there was no problem in saying what I was going to say. I did carry on with ANB from habit as much as anything. But, that was interesting, at the time that they were talking, when the second machine went in at Rossi, certainly it was hoped that the Commission would undertake to burn bark. But, the trouble was that they were so fussy about it that it was just completely impractical. They apparently insisted in the contract on the right to turn the bark off if they didn't like the colour, the shape, the size, the moisture, or anything at all. It gave them complete control over the bark flow to the boiler and Rossi just wanted no part of that. It really unfortunately fell apart just on a simple little thing like that. I'm just as happy it did because otherwise I wouldn't have got the job of doing the plant. You know there's a silver lining to every cloud.

Question: Bill Turner, *Rio Algom Ltd.*

I was quite interested in your parallel operation with the utility where you go from a back pressure governor to speed governor. Did you have any problem with automatic reclosing with the utility, or did they have a time delay before you could isolate yourself from the system?

Answer: Mr. Newby

No. this has worked out pretty well on all accounts. Somebody, yesterday from Hydro referred to the possibility of damage from poor synchronization in the first place. Abitibi did spring for an automatic synchronizing device which subsequently concluded that they probably could have done without. The operators have been trained in the older power station and they can synchronize with their eyes closed, but it does have automatic synchronization. In the case of a trip-over like that, no this hasn't been a problem. In general, of course, it trips over owing to storm conditions on their own line knocking off the line. So they are cut loose from the system then anyway and with the steam turbine and the hydraulic units they can then maintain production.

Question: Mr. Turner

What I mean is, if you don't open your time breaker rapidly enough you try to carry the whole system on your own plant.

Answer: Mr. Newby

Well, there is . . . I couldn't give you in detail all the exotic gadgets that are involved, but there is of course reverse flow protection and every other thing I could think of in the electrical circuit. I think they even worry about which direction the wind is coming from, but I'm not really sure.

Question: Mr. Turner

I have a problem where you have a three cycle under frequency relay trying to open an eight cycle circuit breaker, and the Hydro, of course I'm being factious here, re-close in five cycles. You know it's a pretty hellish thing to live with.

Answer: Mr. Newby

Yes, well if you're interested in it in more detail, I could either get you the necessary drawings or better still suggest you talk to Abitibi because they are pretty familiar with coping with Hydro problems up there in the light of their cost of living with them, and their water control problems and everything else. But, there hasn't been any problem from that respect.

Answer: Alex Juchymenko, *Ontario Hydro*

Some questions are asked about present capital costs, and as you know yesterday, Mr. Dick, in his study, had looked at various costs in the last two or three months I have information on the fifteen mills (or fifteen installations.) The present cost of cogeneration units run from about $260 to about $880 per kilowatt, depending on the size and where it is installed. Now, the other thing I'd like to say is that the report which Mr. Dick was talking about is a very long report. I guess that's why he had problems summarizing it. Part of this report will be available in the transcript that we will send to you in January. There are some problems, of course. We cannot identify where the information came from and it would be in a summary form. But, I'd just like to indicate that the whole study which was undertaken in the last year is in these four volumes. These will be summarized in the book. But, if you have any questions as far as the costs, are concerned just for your own interest now, we have most of it here -most of the capital cost, operating cost and fuel cost. Another interesting thing is that people who are using the so called "free fuel". . . do not necessarily have the lowest mill rate. As a matter of fact, in most cases they don't. So I guess it's like Ontario Hydro's nuclear plant; the fuel is very inexpensive (2 or 3 mills per kilowatt) and yet the cost of capital to utilize that fuel is very expensive. I guess it is the same thing with the refuse that Bill was talking about.

Answer: Mr. Newby

Alex, I'm glad you brought that up and this is something I really should have checked with you earlier. Those figures I used in the conclusions of the cost of central stations by comparison, Alex was kind enough to furnish to me. I had somebody question the figure of $760 for nuclear at that time, and the question I couldn't answer was whether or not that included the original charge of heavy water, and if not, what that would do to it. I don't know the answer to that and I kept meaning to ask you before. I was just wondering because the latest stories that I hear seem to be that nuclear is going to come in around $2,000 per kilowatt and I wondered whether by any chance that $760 might have not included heavy water. But anyway it isn't really relevant as far as the point of the paper is concerned.

Question: Mr. J. Cullain, *INCO*

I think there was a question that was left unanswered. It was the concern expressed regarding. . . the cost of nuclear power plants and nuclear installations, and Mr. Harold West would like to make a comment on this to try and clarify this in everybody's mind.

Answer: Harold West, *Ontario Hydro*

It doesn't make sense for Ontario Hydro's seminar not to be able to answer a question like, "What do our plants cost?" So, just to clarify that point, a plant that would be going on line today (a nuclear power, a base load plant) is costing approximately $900 per kilowatt, all costs including the heavy water. The Darlington station which will be going in service in 1984/1985 is presently running at $1,500 per kilowatt. That would be at the time it goes on line, of course, and that also includes the heavy water cost.

Design and Economic Differences between Coal and Oil Fired Boilers

D. K. RIVERS,
Babcock & Wilcox Canada Ltd.

Around 1960, relatively inexpensive package type oil and gas fired boiler designs were introduced, which accelerated the shift to oil and gas. They had the advantage of being installed for less than half the cost of coal fired boilers. However the soaring cost of oil fuel has reduced the capital advantage of the package type boiler and industry is again looking at coal as a source of energy. This paper will discuss boiler design differences for similar capacities of coal and oil. Economic comparison of a range of capacities for both fuels will be reviewed for several typical turbine pressure and temperature conditions.

Introduction

I plan to review with you a table showing 32 approximate selling prices for a specific list of normal steam generating equipment that is generally supplied by the boiler manufacturer. Sixteen of these prices are for coal units and 16 for oil units, but they will be broken down into four steam flow capacities of:-

100,000 lbs. of steam per hour
200,000 lbs. of steam per hour
300,000 lbs. of steam per hour
400,000 lbs. of steam per hour

For each of these capacities, a separate price is provided for each of four nominal turbine pressure and temperature conditions of:-

600 - 750°
800 - 825°
900 - 900°
1250 - 950°

The lbs. of fuel used is also contained in the table which would enable a multitude of economic studies and evaluations to be made both on the cost of the capital equipment, cost of power and the cost of process steam.

Leading up to the presentation of these prices, I will show you pictorially with approximate dimensions, the difference in space requirements for these four capacities between coal and oil firing. In addition I will briefly highlight some of the major design parameter differences between coal and oil that result in this difference in size and space and, therefore in the cost of this capital equipment.

History - Our past experience as suppliers of steam generating equipment for cogeneration in the industrial market has been primarily with the pulp and paper industry and, to some extent, with sugar refineries and oil refineries. These industries are heavy users of process steam, but it also makes a lot of sense for them to also produce electricity. As much as 80% of the energy supplied is then used compared to about 35% for a thermal power plant which has to reject the waste heat. Many of these mills were located in remote areas where power was not available. Pulp mills again had an ideal situation of free fuel except for handling costs in order to dispose of bark and sawdust. Recovery units are also in a similar category of "free' fuel with steam as a byproduct. These units are usually installed with a high pressure temperature condition to produce power, with process steam bled off at several pressure points for digesters, paper machine dryers, liquor evaporators and also building heat.

Many paper mills, particularly in the Quebec area have for over 30 years installed future high pressure temperature boilers. Therefore, even though they were located in areas of electricity supply, they were constantly in a position to produce their own power if the rates were not economically satisfactory. Certainly many of these boiler installations go back even further than 30 years with the future high temperature condition, but have never been converted. A further reason for producing power again in remote areas was the frequent interruptions associated with being at the end of the power line.

A number of these units were always multi-fuel, that is, bark and coal, bark and oil, and in some cases, all three fuels for a greater flexibility in fuel selection.

Regarding multi-fuel installations, many of the grey and white haired gentlemen here today will recall that after World War II, there was a flood of industrial units installed for initial oil and/or gas firing but desigend for future coal. The reason was that during the war many of the so-called "non-essential" industries were not able to obtain sufficient oil and did

not want to be caught in this squeeze again. Even small units for breweries such as 30,000 and 40,000 lbs per hour units were initial oil and gas but designed for future addition of a stoker.

Cogeneration in more recent times has occurred in other industries such as at the Nova Scotia Power Corporation plant where an 80 MW unit produces process steam for the Atomic Energy Heavy Water Plant at Point Tupper, after power requirements have been fulfilled.

Municipal waste should be an ideal future fuel source to produce power for neighbouring industry, and even to produce steam for building heat. Central heating, unless starting from fresh, is a major capital undertaking. City of Winnipeg and City of Vancouver and even Toronto are examples of existing central heating systems. It seems logical that disposal of minicipal and industrial waste should be combined to produce power, process steam and central heat.

A return to coal firing is generally predicted in North America and in fact dictated bythe legislators south of the border. In September, I had the pleasure of hearing at the annual meeting of the Canadian Boiler Society, Mr. W. H. Axtman, Acting Executive Director of the American Boiler Manufacturers Association bring us up to date on the ABMA activities. One of their programs was lobbying congress for a change on the capacity of new boiler installations of 50 million BTU output and above to be dictated as coal only firing. ABMA lobbied for 300 million BTU and above. They did succeed in having the 50 million BTU output changed to 100 million. It was most interesting to be told that many congressmen thought conversions were a simple matter of replacing an oil burner with a coal burner. This was a major education program for ABMA. They started with the simple questions of: where would they put their coal pile; where would they put their coal bunkers; where would they put their coal handling equipment; their ash handling equipment; the new dust collectors, or most probably electrostatic precipitators. They finally met with more success on conversions than they did with new installation sizes for coal only firing. From my crystal ball, industry in Canada will probably, in the long run, be able to remain more with oil and gas than a general move to coal, particularly as more western Canadian synthetic oil arrives on the market and oil exports are phased out.

Space Requirements

I would now like to show you some slides of the space required for corresponding sizes of oil and coal. On Fig. #1, the 100,000 and 200,000 lbs. per hour units oil fired are shop assembled or "package" style designs.

The block areas on Fig. No. 1 indicates only the pressure part space with no attempt to show heat traps, ducts, flues, stacks, etc. The 100,000 lbs. coal fired unit shown is a stoker size. The plan area of 16 x 30 for oil and 18 x 32 for the coal is not much different, but the height difference is almost 3 times at 48 feet versus 17 feet. The plan area for 200,000 oil, again being a "Package" style design is not too much different for coal but in this case the height for a pulverized coal unit is not just 3 times higher but actually 4 times higher. Actually the 200,000 lbs/hr oil unit, although package design, is too large to ship shop assembled and in fact has to be field erected.

We have chosen pulversized coal for this 200,000 lbs. size since the trend is toward pulverized coal primarily for cogeneration as the thermal efficiency is 2% to 5% higher for PC over stoker and usually the fuel cost is lower. Stokers have, in their hay-day, been supplied for capacities of 300,000 lbs/hr. and in fact even as high as 400,000 lbs./hr. On the other hand, we have supplied pulverized coal units for as low as 100,000 lbs./hr.

Looking at the 300,000 and 400,000 lbs./hr sizes, the oil is now what we normally refer to as a field erected style. Again the plan areas are relatively close but the height is at least double, and in the 400,000 lbs/hr. size 2-½ times the height of the oil fired installation.

When adding a coal fired unit to an existing plant, height is always a real problem.

Although this Fig. 1 indicates 2, 3 and even 4 times the height required for coal over oil, there is even a more dramatic space requirement difference when the auxiliaries are included. Fig. #2 shows the 400,000 lbs./hr. size comparison. The height of the coal unit is now shown over the steel at 137 feet or almost 3 times the height for the same capacity on oil at 52 feet.

A most dramatic space requirement is obvious from the side elevation showing a distance from the bunkers to the stack on the coal unit of about 155 ft. Only 1/3 of this distance is required for oil firing from the burners over the air heater, which includes the area for a side position stack.

In addition, coal fired units require outside space for a coal pile, coal conveying equipment, ash handling and perhaps even an ash silo for final removal and disposal of the ash.

Fig. No. 2 very dramatically shows the space difference. Equally dramatic is the cost difference for this capital equipment for the same function.

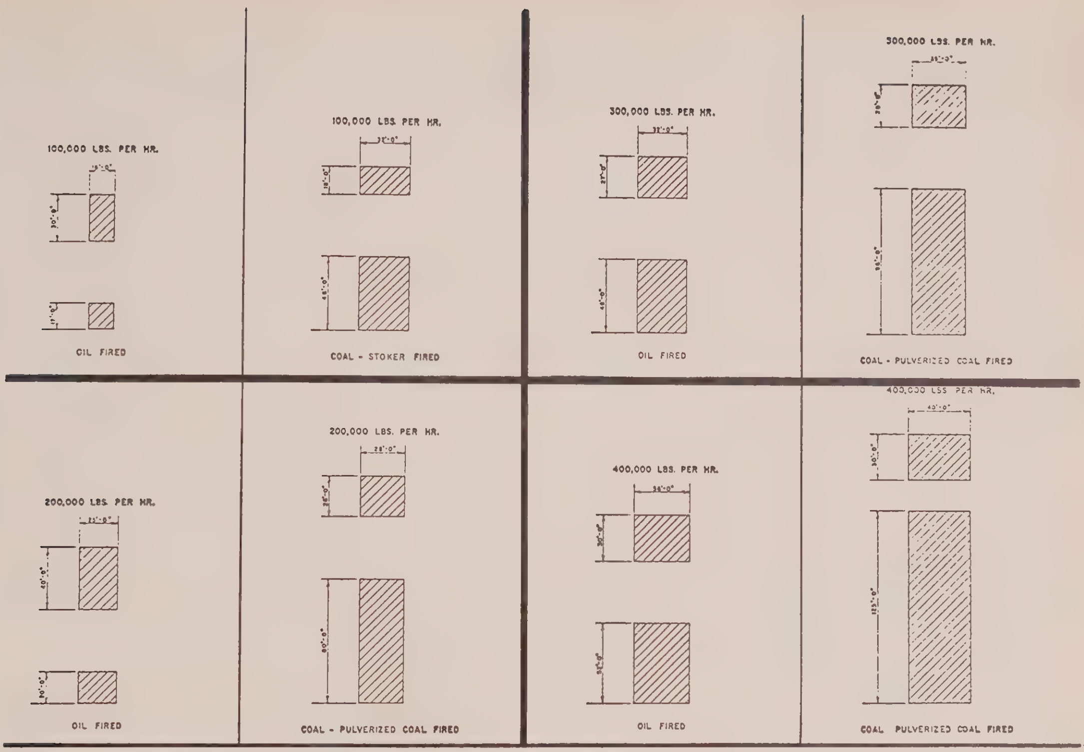
The oil fired unit shown is very typical of designs offered with a long narrow furnace, a tall narrow boiler tank, and compact arrangement of heat trap flues ducts and stack.

Design Parameters

Now let's have a look at the cause of the vast difference in sizing and space requirements. We have seen the "effect" on space requirement.

Items such as coal bunkers, recent environment demands for electrostatic precipitators in place of dust collectors, need for a coal pile, coal conveyors, ash conveyors and ash silos must be considered when comparing coal to oil. There are many design consideration differences, so let's take a look at a list of these considerations through the eyes of the boiler designer, which will again amplify the reason for the difference in size, difference in space and difference in price.

Furnace exit temperatures, furnace release rates, gas quantities, gas velocities and tube spacing are the ma-



Babcock & Wilcox Canada Ltd. - Fig.No.1

jor items that are the cause of the large size and cost differences between coal and oil.

Fig. Nos. 3, 4 and 5 list 12 items of design consideration differences.

The most important design consideration for steam generating units is the fuel to be burned. Fuel storage, handling, preparation equipment, ash handling equipment, burning equipment, furnace design, convection bank design, heat recovery equipment and gas clean-up equipment, are fuel dependent and vary considerably, depending on the kind of fuel to be fired.

The major differences between coal fired and oil fired steam generators are a result of the solid form of coal prior to burning and the ash contained in the products of combustion. The products of combustion from burning oil contain relatively small amounts of ash. On the other hand coal, particularly lower grades, produces vast amounts of ash.

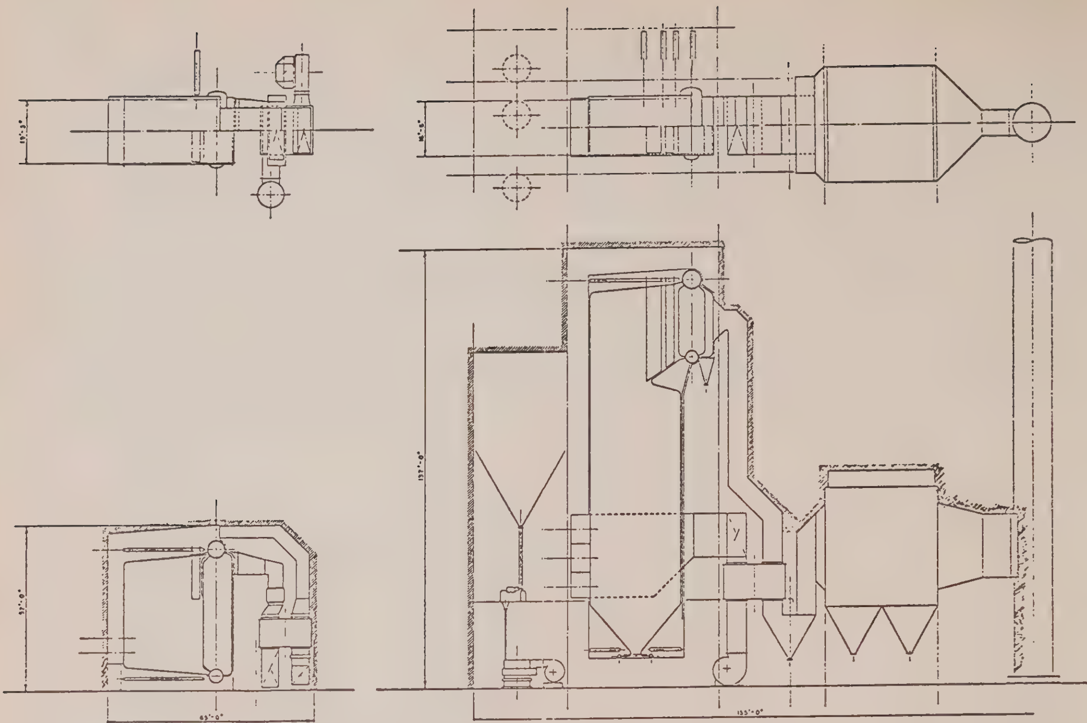
Looking at Fig. #3, we have the obvious considerations of outside and inside storage for oil versus coal with the handling and preparation for oil requiring only pumping and heating while coal requires conveyors crushers and feeders and often drying.

Fig. No. 4, lists the major design differences.

Furnaces on coal fired designs are much larger than on oil fired designs because the coal enters the furnace in the form of solid particles, whereas, oil is atomized to a fine mist. The solid coal particles require a much longer residence time within the furnace to complete the combustion process. To ensure adequate furnace volume to complete combustion, furnace liberation rates in BTU's/hour/ft^3 of 30,000 and less are specified and used for coal designs, whereas, on oil designs, liberation rates as high as 125,000 BTU's/hour/ft^3 have been used.

To minimize slagging on the furnace walls of coal fired units, furnace release rates in BTU's/hour/ft^2 are in the order of 75,000 compared to oil where values as high as 225,000 have been utilized.

To minimize slagging in the high burner input zone, it is common practice to limit the amount of heat released in this area to a value of approximately 300,000 BTU's/hour/ft^2 for lower grade coals, and upwards of approximately 600,000 for better grade coals. The burner zone heat release rate is controlled by limiting the input to burners to approximately 165 million BTU's/hour compared to oil at 250 million BTU's/hour, thereby necessitating a greater number of smaller burners on coal firing. Furthermore, the distance between coal burners is very often spread to help maintain low values on burner zone release rate. Heat input to furnace plan area is also a major factor in controlling furnace slagging, and values of 1.0 to 2.2 x 10^6 BTU's/hour/ft^2 are normally specified and used. With high slagging coals, a lower furnace plan area release rate is used.



400,000 lbs. per hr. Babcock & Wilcox Canada Ltd. - Fig. No. 2

Oil & Coal
Power Plant Design Considerations

	Oil	Coal
1. **Outside Storage**		
Method	- Tanks	- Pile
Maintenance	- Tank Heating	- Spontaneous Combustion - Weathering - Wind & Water Erosion
Area	- Minimal	- Extensive
2. **Inside Storage**	- None	- Bunkers
3. **Material Handling**	- Pumped	- Mechanical Conveyors
4. **Preparation for Burning**	- Heating	- Crushing - Stokers
	- Boost Press.	- Pulv. - P.C. Firing - Drying

B&W Canada Ltd.
Fig. No. 3

	Oil	Coal
5. **Burning**		
Burner Input - Max. BTU/HR	- 250 x 10^6	- 165 x 10^6
Air Temp.	- Cold Acceptable	- Hot Req'd
Burner Clearance	- Minimal	- Liberal
6. **Furance Design Range**		
Configuration	- Low & Long	- Tall & Narrow
Liberation Btu/hr-ft^3	- 25 - 125,000	- 10 - 30,000
Release Btu/hr-ft^2	- 150 225,000	- 35 - 75,000
Plan Area-Btu/hr-ft^2	- N.A.	- 1.0-2.2x10^6
Burner Zone-Btu/hr-ft^2	- N.A.	-300-600,000
F.G.E.T. °F	- 2400 - 2600	- 1900 - 2400
Wall Blowers	- Not Req'd	- Req'd
7. **Convection Banks**		
Velocities - FPS	- 75 - 125	- 30 - 65
Tube Spacing	- 8" - 4½"	- 9" - 4½"
Arrangement	- Baffled	- Single Pass
8. **Heat Traps**		
Economizer	- Optional	- Optional
Air Heater	- Optional	- Req'd

B&W Canada Ltd.
Fig. No. 4

Oil & Coal Power Plant Design Considerations

	Oil	Coal
9. Gas Clean-Up		
Mechanical Collectors	- Sometimes	- Sometimes
Precipitators	- Not Req'd	- Normally
Bag Houses	- Not Req'd	- Sometimes
10. Ash Handling		
	- Not Req'd	- Req'd
11. Boiler Designs		
Pressurized	- Normal	- Abnormal
Balance Draft	- Abnormal	- Normal
Bottom Supported	- Normal	- Abnormal
Top Supported	- Abnormal	- Normal
12. Fuel Characteristics		
H.H.V. - Btu/lb	- 17-19,000	- 5-14,000
Ash	- 0.01-0.5	- 5.40
S	- 0.5-3.5	- 0.5-8.5
H_2O	- Nil	- 1-40

B&W Canada Ltd.
Fig. No. 5

Even with a proper furnace design, slagging on coal fired boilers will occur and, therefore, furnace wall sootblowers are provided to keep the furnace walls clean. Furnace wall blowers are not required on an oil fired design.

Each of these factors increases the length, width and height of a coal unit furnace over an oil unit.

The furnace exit temperature (gas temperature entering convection surface), must be selected below the initial deformation temperature of the ash, that is - below the plastic state. Otherwise, the ash in the products of combustion will plate out on the convection bank tubes causing bridging and eventual pluggage. To minimize fouling on the convection banks, generous tube spacing must be provided along with low gas velocities, and complete coverage by sootblowers must be maintained. Tube spacing on a severely slagging coal can be as wide as 54" in the form of platen heating surface at the entrance, progressively narrowing down to 4" in the colder gas passes. In an oil fired design, the maximum tube spacing is usually 8" and 4" in the hot and cold passes respectively.

Gas side velocities on a coal fired unit generally range anywhere from 30 to a maximum of 65 ft./sec. compared to an oil fired design of 75 to as high as 125 ft./sec.

Coal fired designs normally limit the furnace exit gas temperature in the range of 1900 to 2400°F, whereas, oil fired designs are limited to temperatures not exceeding 2600°F.

The lower temperatures and lower velocities for coal firing requires more square feet of heating surface in the convection banks, which directly affects the size and the cost.

Because of the increased ash loading, coal fired units are equipped with many more sootblowers than oil fired designs.

In designing a coal fired unit, the boiler designer first realizes that:-

the furnace must have sufficient volume to complete combustion of the solid coal particles.

the burners are limited in input, and also spread to control slagging.

the furnace wall areas must be extensive to reduce the gas temperature below the ash softening temperature before entering the convection banks.

next the designer realizes that the spacing of the convection banks must be liberal to prevent bridging, and also to produce low gas side velocities to minimize gas side erosion.

Scope of Supply for Prices in Fig. No. 7

Oil Fired

Boiler with Mountings
Superheater with Mountings
Economizer with Mountings and/or Air Heater
Oil Burners and Burner Box
Air Ducts from F.D. Fan
Flues to Heat Trap Outlet
Bottom Support Steel for Boiler and Heat Trap
Steam Coil Air Heater
Sootblower with PVF
F.D. Fans & Motor Drives
Applied Insulation
Freight to Ontario -Quebec Area
Start-up Service
Field Erection

Coal Fired

Boiler with Mountings
Superheater with Mountings
Pulv. Coal Burners
Pulverizer and Motor Drives
Coal Feeders

Coal Piping from Feeders
Air Heater
Air Ducts from F.D. Fan
Flues to A.H. Outlet
Top Support Hanger Rods
F.D. Fan & Drive
I.D. Fan & Drive
P.A. Fan & Drive
Pulv. Seal Air Blower

Sootblowers with PFV
Steam Coal air Heater
Electrostatic Precipitator & Lagging
Applied Insulation
Freight to Ontario -Quebec Area
Start-up Service
Field Erection

Stoker Fired

Rotograte Stoker & Coal Feeder
Stoker Support Steel
Overfire Air Fan & Drive
Ash Hopper & Doors
Dust Collector

Fig. No. 6

With low gas temperatures, low gas side velocities, the heat transfer across each type of convection bank is extremely poor in comparison to high temperature high mass flow oil fired units. Consequently, the convection banks, like the furnace, are much larger than a

comparable capacity oil fired design. The end result is that both the furnace and the convection banks are much larger for coal fired units than for oil. It is not uncommon for a coal fired boiler to have at least twice the surface of a comparable oil fired unit. This ratio is even greater when poorer grade coals are used.

Coal fired designs also require additional heat recovery and gas clean up equipment not normally found on oil fired units.

With coal firing, both air heaters and economizers are commonly found, whereas, on oil fired units, it is quite normal to install only one heat trap. In addition, because of the vast amounts of ash inherent in coal, highly efficient gas clean up equipment in the form of bag houses or electrostatic precipitators are required to clean the gas before exiting to the stack. Most oil fired installations do not require gas clean up equipment.

Looking at Fig. No. 5 under item 11, boiler designs, it is most normal for oil to be pressure fired and coal to be balanced draft. To provide adequate residence time for burnout of fuel particles, the pulverized coal fired units have tall vertical furnaces and are therefore top supported. However, oil fired designs, because of their low head, can normally be bottom supported.

Under fuel characteristics, item 12 on Fig. No. 5, you can see that the percent ash in coal can range anywhere from 5% to as high as 40% by weight and therefore sophisticated ash handling equipment is required to remove the fly ash from the bottom of the furnace hopper, the boiler bank hopper, the air heater hopper and the gas clean-up hoppers.

Cost of Steam Generating Equipment

Fig. No. 7 contains a total of 32 prices for oil versus coal for the four capacities of 100,000 lbs./hr. up to 400,000 lbs./hr. and for the four pressure-temperature conditions vertically for nominal turbine operation starting at 600 lbs. 750° and finishing with 1250 lbs. 950°.

The cost of the oil design for the 100,000 lbs./hr. and 200,000 lbs./hr. capacity in figure No. 7 are for the package type design.

The 100,000 lbs./hr. oil size is shop assembled.

The 200,000 lbs./hr. oil size in most cases is too large to be shipped complete as a shop assembled unit and therefore is shipped partially or wholly knocked down for finish field assembly.

Since the package design concept has a higher furnace release rate, higher convection velocity and cross flow rather than long flow, the 100,000 lbs./hr oil size is several $/lb. lower cost than the much larger field erected oil capacities of 3 and 400,000 lb/hr. Consequently the coal fired price for 100 and 200,000 capacity is 3 times the price of oil.

for the 300 and 400,000 lbs./hr. sizes the coal cost only 1-½ to 2 times the cost of oil equipment of the same capacity.

Comparing cost of coal to oil equipment, a very general rule of thumb is that the coal boiler equipment is 1-½ times the value of the oil equipment in total when comparing "field erected" style larger size oil unit with coal. This statement is true for a good bituminous coal.

If the coal being fired is a lignite with low BTU, high ash and high moisture content, high slagging and low ash fusion temperature, then a general rule of thumb is that coal is twice the cost of oil equipment.

This rule of thumb is not really that evident from the data on Fig. 7 for the large sizes since we have included electrostatic precipitators in the PC firing prices. If the

APPROX. TOTAL CURRENT ERECTED PRICE FOR SCOPE OF SUPPLY PER FIG. NO. 6
THOUSANDS OF DOLLARS
($/LB. OF STEAM)

CAPACITY	100,000# Steam/Hr.		200,000# Steam/Hr.		300,000# Steam/Hr.		400,000# Steam/Hr.	
Firing Equipment	Oil	Coal Stoker	Oil	Pulv. Coal	Oil	Pulv. Coal	Oil	Pulv. Coal
Steam Conditions								
600 PSI-750°F	690	2050	1070	3630	2570	4515	2980	5175
	(6.9)	(20.5)	(5.3)	(18.1)	(8.6)	(15.1)	(7.5)	(12.9)
800 PSI-825°F	745	2180	1145	3840	2810	4800	3250	5510
	(7.4)	(21.8)	(5.7)	(19.2)	(9.4)	(16.0)	(8.1)	((13.8)
900 PSI-900°F	790	2310	1210	4060	3020	5070	3500	5820
	(7.9)	(23.1)	(6.1)	(20.3)	(10.1)	(16.9)	(8.7)	(14.5)
1250 PSI-950°F	855	2500	1310	4420	3340	5520	3825	6345
	(8.5)	(25.0)	(6.6)	(22.1)	(11.1)	(18.4)	(9.7)	(15.9)
Efficiency	88	85	88	88	88	88	88	88
Fuel Range lb/hr								
Oil -18200 BTU/LB	7050-7600		14100-15200		21150-22800		28200-30400	
Coal-12000 BTU/LB		11070-11940		21380-23070		32075-34600		42770-46130

FIGURE #7

precipitator is removed from the price then the 1-½ times rule of thumb is quite evident.

For your information for the 200, 300 and 400,000 lbs./hr. sizes the precipitator value is 550,000, 700,000 and 750,000 dollars respectively for all pressure conditions. This is a sizeable figure but nevertheless a necessity to meet today's environmental requirement, while previously a much lower cost dust collector was only necessary.

Stoker units at the moment are still acceptable to environmental people in the country with high efficiency dust collectors.

I cannot really provide any rule of thumb for pricing moving in a vertical line for a given capacity for change of temperature and pressure conditions. This actually varies for the style of unit selected.

A cost figure percentage for pressure only changes has often been used by people in the business but in this case you also have changes in temperatures. Therefore you will not find a constant percent change in the vertical portion of this table.

A very simple list of items that cause the vertical cost variation is:

Slight size change to some of the equipment with an input difference for pressure and temperature changes.

Major change due to pressure.

Major change in the size of the superheater surface with degrees of superheat increasing for all conditions and as much as 16% with the exception of the change from 900-900 to 1250-950 which is negligible.

Dramatic cost change in superheater metals once the steam temperature goes above the 750 to 800° range.

The prices are current delivered and erected for the Ontario and Quebec area of Central Canada. Prices are suitable for use as estimating prices and can be most readily used for budget studies.

We have added the pounds of fuel to this table, the minimum being the requirement for the 600 lbs. 750 and the maximum for the 1250 lbs. 950 condition. Therefore with the cost of fuel known for a given area further economic comparison can be studied.

For ease of comparison we have also shown in brackets the dollars /lb. of steam. Certainly it would be most practical to extrapolate using the dollars/lb. of steam from one condition to another for a fairly reasonable price of equipment between any two given capacities and between any two given steam temperature pressure conditions.

We have not attempted to show prices on a dollars/ KW basis primarily since the turbine heat rate curve is very steep in these low pressure temperature conditions and of course would vary considerably from plant to plant each with a different number of back pressure bleed off conditions.

Closing

It is hoped that the pricing shown on Fig. No. 7 for the various sizes, pressures, scope of supply for the equipment, including the pounds of fuel, will be useful for your future studies to review the net installed cost of total equipment, cost of fuel, cost of power and cost of process steam for co-generation for oil versus coal.

South of the border, there is no choice but to go coal firing. At the moment, this is not the case in Canada. The vast difference of plant space requirement is, of course, also a very critical item particularly for existing plants.

Although we have only briefly highlighted the design parameter differences between oil and coal for similar capacitities, we trust that this has given you perhaps a slightly better understanding of why there is such a vast difference in size, layout requirements and cost of equipment.

Discussion:

The Design and Economic Differences Between Coal and Oil or Gas-Fired Boilers for Cogeneration

DON H. RIVERS, *Babcock and Wilcox Canada Ltd.*

Question: Gaston Beaucher, *Hydro Quebec*

Say, you said that the field erection was included. Is that only supervision of the field erection or are we to add labour?

Answer: Mr. Rivers

All erection.

Question: Mr. Boucher

Second question - how would bark burning boilers compare with the coal or oil in percentage differential?

Answer: Mr. Rivers

I don't know if I can give you that off the top of my head. If you compare its state to oil, it's going to be a fair percentage more. I think it's probably closer to the . . . It would be between the two. It would be less than a coal-fired job. A pulversized, you're going to have a stoker in today's conditions. It might be very close to the coal-fired price. It's a much bigger one again, because of the gas quantities, the surfaces

have to be opened up. It would be very close to the coal price.

Question: George Weldon, *Union Carbide*

In either the oil or the coal boilers in your prices did you have any sulphur control of any kind? You have electrostatic I presume for the particle, did those prices do anything for sulphur or are we going to live with the sulphur level you have in your fuel?

Answer: Mr. Rivers

I think you may have some changes in burners for knock control with the burners on, yes.

Question: Mr. Weldon

Does Babcock Wilcox have a fluidized bed design or have you done any work in this field?

Answer: Mr. Rivers

We have done some work on this thing. There are some of our other competitors that are working quite heavily on this right now, if we aren't, we will be.

Question: John Davies, *Ebastec Lavalin Inc.*

I would like to direct a question on impregnable boiler design please. It has always been my experience that a boiler manufacturer designs a boiler to suit one particular coal. The modern-day power plant, however, demands such a vast amount of coal that more than one coal supply is normally required for that plant. Does your modern-day boiler design contain sufficient flexibility to deal with more than one type of coal, as each coal has its own burning, characteristic, and its own ash characteristic etc.

Answer: Mr. Rivers

Yes, if it has been specified, in other words, you can only design to the coal specification that the customer has given you, and when they do have these variables, and we have them in many cases, they will give us a worse coal, we have even had three conditions. So we have to design within certain limits of either temperature, efficiency etc, but we have to design for the worst coal condition, and therefore, our pulverizers and such have to be selected this way within -1 for the worst coal to do the capacity only, and you may have to live with what temperature is there, but this is usually specified by the customer, and it is reiterated by ourselves in our performance data that we give the customer in the proposals stages for the three conditions of fuel. So, yes, if the customer knows he's going to get a wide variation, and he wants the design that way, we design it accordingly.

Question: Mr. Pasquet, *W.P. London & Associates*

I noticed that you quote the same efficiency - 88% for both coal and oil fired. I can understand the 88% with oil which has probably relatively low excess air. Can you actually obtain that with a coal fired boiler?

Answer: Mr. Rivers

Yes, we have that and 89% in areas, and 90% on coal.

Question: Mr. Pasquet

But it is always comparable? You mean you can get the same comparable efficiency?

Answer: Mr. Rivers

I did this primarily to say this is on an equal scope of supply, on an equal basis, in order to make the prices relate so that my air heaters were about the same level of pricing.

By-Product Fuels for Use in Cogeneration Systems

R. D. WINSHIP
K. W. MORRIS
L. SMITH
Combustion Engineering Canada

This paper mainly addresses the subject of back pressure power which is achieved by increasing the steam pressure and temperatures as required by process steam boilers. The costs for the above are included. The additional ancillary equipment required for a plant generating back pressure power is discussed. Some technical limitations resulting from the nature of these by-product fuels have an effect on high pressure and high temperature steam geneation. This will also be presented and discussed.

Introduction

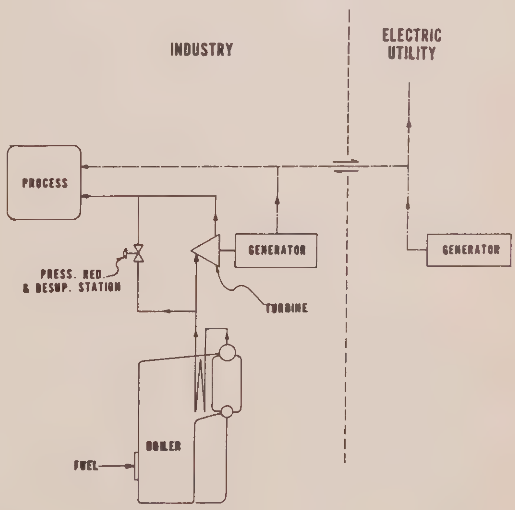
On-site cogeneration can be described as the production of both electricity and process steam at one location. To be advantageous, cogeneration must be economically competitive with purchased electricity or turbine driven equipment. Considering the three prime fuels, natural gas, oil and coal, there has not been in Canada very many cogenerating projects due to the relatively low cost of electricity.

The attractiveness of cogeneration with byproduct fuels will increase as electricity costs and primary fuel costs increase. For this presentation, byproduct fuels include black liquor and bark in the pulp and paper industry, blast furnace gas in the steel industry and CO gas from catalytical regenerators in the refinery industries. In Canada today, cogeneration has largely been limited to the pulp and paper industry. A substantial number of boilers have been installed suitable for future conversion to cogeneration.

Figure I shows the basic cogeneration system arrangement considered in this presentation. To date, in most cases the power generated by industry has usually supplied a portion of that industry's power requirements and none has been exported to the local utility. At present, consideration can be given to the industrial export of power to the utility. This will call for cooperation with a local utility in that the industrial unit generators and excitation control systems should be maintained and adjusted to provide reasonable stability to the inter-connected power network.

The basic advantage of cogeneration is that the overall utilization of energy may be very much higher than in the case of power production only. The cycle shown in Figure I has a heat rate of energy input to power produced typically of 4,000 to 5,000 BTU per kilowatt hour, when no heat is rejected to a condenser. Unavoidable losses occur only in combustion, the generator, and that portion of the turbine exhaust which does not become process steam; the combustion losses depend on the type of fuel fired. Steam turbine topping cycles generate, per unit of process steam, relatively low power compared to condensing electric utility turbine generators and the efficiency in cogeneration plants of the condensing portion of electrical generation will be at a slightly lower efficiency than in a large central station utility plant; however, utilizing low cost byproduct fuels, the cost per kilowatt hour of electrical production will still be comparatively attractive.

FIG. #1



Today, economic considerations seem to dictate applications of 10 megawatts or more of electrical generation.

Byproduct Steam Generators

Steam generators utilizing byproduct fuels or gases have long been used by Canadian industry and hence, the equipment utilizing these fuels may be considered a mature technology. Table I gives a typical analysis of these fuels and for comparison, a typical oil and coal analysis. It also includes typical efficiencies for the utilization of the chemical and sensible heat contained therein. As these fuels have a lower heating value than the primary fuels, the costs of steam generating equipment utilizing them is relatively more expensive. Table 2 gives the relative cost for units of the same steam capacity (500,000 lbs/hr) pressure and temperature for the different fuels and is based generally on arrangements as shown in Figures 2, 3, 4 and 5 of typical steam generating equipment. These byproduct-fuel-fired units have been used in cogeneration plants and have been successfully operated at high steam temperatures and pressures, where maximum benefits can be derived from cogeneration. However, in two cases there are precautions which should be observed

FUEL ANALYSIS

TABLE I

WT %	OIL	BARK	COAL	COG	BLAST FURNACE GAS	BLACK LIQUOR
C	86	26	47	-	0.3	26
H_2	11	3	3	-	-	2
S	3	-	0.2	-	-	2
N_2	1	-	1	68	50	-
O_2	1	20	13	-	-	20
CO	-	-	-	9	21	-
CO_2	-	-	-	14	29	-
SO_2	-	-	-	1	-	-
H_2O	-	50	20	9	-	35
Na	-	-	-	-	-	14
ASH	0.1	1	17	-	-	1
HHV (BTU/LB)	18,000	4,350	7,840	390	1,050	4,225
HHV (BTU/FT^3)	-	-	-	33	86	-
EFFICIENCY %	89	68	85	77	83	67

Steam Generators Relative Cost For Different Fuel Types

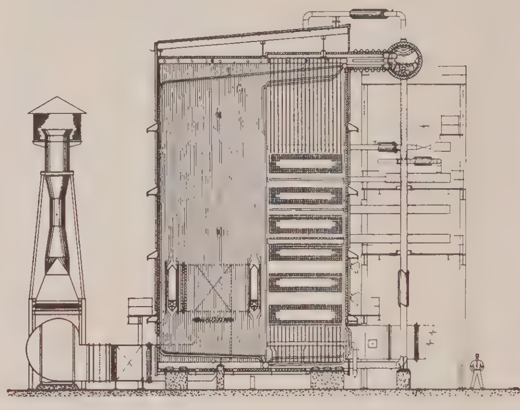
Table 2

Fuel Type	Relative Cost
Oil	1.0
Nat. Gas	.95
Coal	2.75
Bark	2.0
Blast Furnace Gas	1.25
CO Gas	1.25
Black Liquor	2.60

Relative Cost for a Natural Circulation type steam generator designed for 500,000 lb/hr evaporation for various fuels.

CO GAS

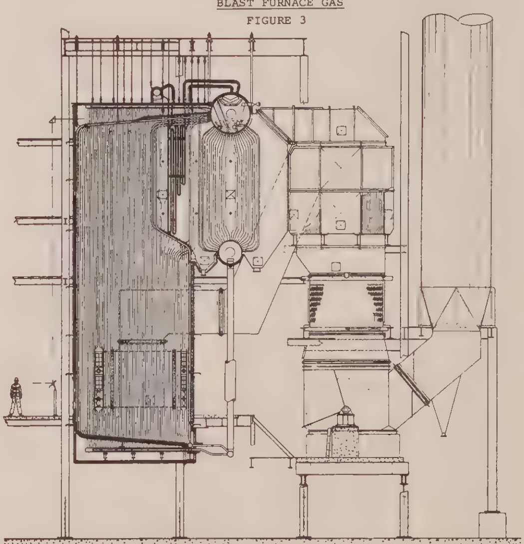
FIGURE 2



COMBUSTION ENGINEERING-SUPERHEATER LTD.
MONTREAL, CANADA
TYPE MU STEAM GENERATOR
FOR
SHELL REFINING COMPANY LIMITED

BLAST FURNACE GAS

FIGURE 3

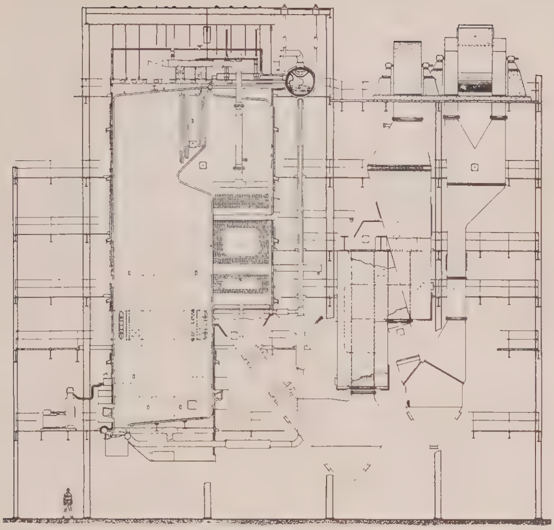


CE CANADA
COMBUSTION ENGINEERING SUPERHEATER LTD

TYPE VU—40S STEAM GENERATOR
FOR
THE STEEL COMPANY OF CANADA LIMITED

BARK

FIGURE 4



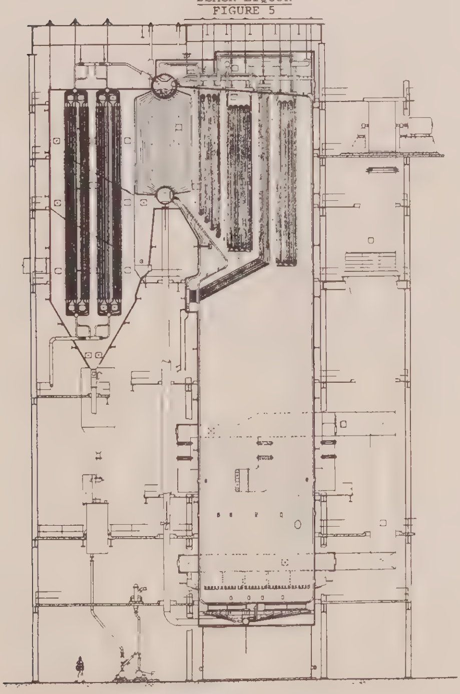
CE CANADA

TYPE MU-X STEAM GENERATOR

DONOHUE ST. FELICIEN INC.

BLACK LIQUOR

FIGURE 5



CE CANADA

COMBUSTION ENGINEERING-SUPERHEATER LTD

TYPE V2R CHEMICAL RECOVERY UNIT

KIMBERLY CLARK PULP AND PAPER LTD

in order to get maximum availability from the steam generating equipment. In the case of pulp mill black liquor fired units, tube wastage from corrosion in both the furnace and superheater, increases as the saturation and superheat temperatures increase. Recently, methods of prolonging the furnace tube life have been developed field trials on suitable materials to extend superheater tube life are underway. In a small percentage of cases with hog fuel (or bark) firing, superheater corrosion has been a problem when the fuel fired contained substantial amounts of chlorides. The most probable source of the chlorides has been salt water. In the case of chamical recovery units, steam temperatures in excess of 825°F usually result in additional maintenance costs due to corrosion. These corrosion rates in chemical recovery units can be further accelerated by significant chloride contents in the liquor.

The use of byproduct fuels should be expected to enhance cogeneration projects. The cost of these fuels are usually substantially below primary fuel costs and in most cases, utilizing their inherent sensible and chemical heat provides the most economical method of disposal of these byproducts. In pulp mills using the sulphate process, recovery of the chemicals in the waste black liquor steam is an economic necessity. Steam generation as part of this recovery process is a bonus. In some cases byproduct fuels can be purchased where their cost per heat unit is substantially less than that of primary fuels.

Water Treatment

As consideration is given to high steam pressures, so as to more effectively utilize cogeneration possibilities, the water treatment facilities must also be made available to produce higher quality water. There is both an increased capital and operating cost associated with improved water quality. In most cases, this increased cost is relatively minor compared with the overall plant capital and operating costs. While competent staff are required to monitor and operate the water treatment equipment, the technology level required is not above that normally available in the subject industries. As the quality of boiler water utilized increases, so does the reliability and availability of the equipment. This point is often considered offsetting the increased capital and operating cost of the upgraded feedwater treatment system.

Another point which makes generalizations about cogeneration costs and plants difficult to make, is the quantity of makeup water required. In a typical utility plant, the makeup water quantity may be in the range of one to three percent of the steam generated. However, in the refinery, steel, and pulp and paper industry, the makeup quantity of water required for noncondensing cogeneration use might be approximately 56,35 and 30 percent respectively.

When the exhaust steam from a turbine producing electrical energy becomes process steam, it is usually exposed to a substantial amount of pipe runs and eventually condensed in heat exchangers containing a variety of ferrous and non-ferrous alloys. High equipment

availability requires that corrosion products carried back from process equipment be eliminated, as far as possible, before the water is returned to the steam generator. Equipment is available to both filter out these corrosion products and in most cases, monitor any abnormal increase in contamination due to leakage in these exchangers; in which case, it may be necessary to temporarily dump the return condensate until the equipment can be repaired. Combustion Engineering recommendations for feedwater and condensate treatment in plants is contained in an abbreviated version in Table 3.

CE RECOMMENDATIONS

FOR

FEEDWATER & CHEMICAL CLEANING

TABLE 3

(1) DEMINERALIZATION EQUIPMENT FOR MAKEUP WATER FOR PRESSURES ABOVE 1,000 PSI AND IN ALL CASES, FOR CHEMICAL RECOVERY UNITS.

(2) DETERMINATION OF FEEDWATER IRON AND COPPER CONCENTRATION WEEKLY.

(3) DETERMINE CHEMICAL CLEANING INTERVAL AND SOLVENTS BASED ON (2).

(4) COMPARE CHEMICAL CLEANING COSTS TO FILTRATION CAPITAL COST AND INSTALL FILLING IN ECONOMICAL DETAILS.

(5) CHEMICAL CLEANING INTERVAL NOT OVER SIX YEARS.

Costs of steam generating equipment for various steam cycle conditions

For cogeneration projects today, the most common steam cycles used are in the range from 600 psi, 750°F to 1500 psi, 950°F. The relative costs of oil fired steam generators for the conventional pressure and temperature levels within this range are shown in Table 4. The relative cost of byproduct fuel fired equipment can be obtained by multiplying these values by the relative cost factors contained in Table 2. The costs are based on those of delivered and erected equipment within Canada, of steam generators with the typical efficiencies contained in Table I and meeting the current practice regarding flue gas emissions. The cost ratios do not include the cost of controls, buildings, platforms, fuel and ash handling equipment, water treatment equipment, turbine generators, feedwater heaters and pumps, condensers, deaerating heaters and interconnecting piping.

There are no technical constraints preventing byproduct fuel fired boilers for cogenerating projects operating at high temperatures or pressures except in the cases previously mentioned concerning high temperature corrosion. The cost data in Tables 2 and 4 is based on equipment generating 500,000 lbs/steam/hr.

STEAM GENERATORS RELATIVE COST FOR DIFFERENT STEAM CONDITIONS

TABLE 4

STEAM CONDITIONS PRESS./TEMP. (PSIG/°F)	RELATIVE COST
600/750	1.[illegible]
850/825	1.07
1250/900	1.16
1500/950	1.27

Relative Cost for a Natural Circulation type steam generator designed for 500,000 lb/hr evaporation for various steam conditions.

Steam Generator Size - Cost Ratios

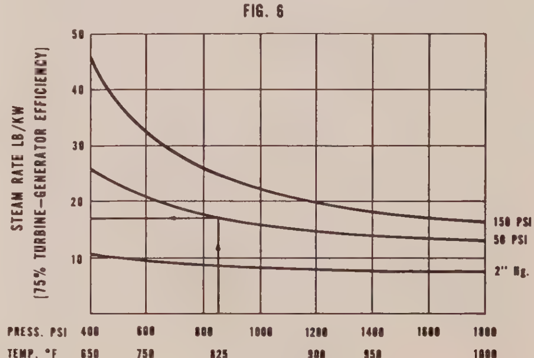
Table 5

Size	Oil-Natural Gas CO Gas -B.F.Gas Black Liquor	Coal-Bark
250,000 LB/HR	.62	.67
500,000 LB/HR	1.00	1.00
750,000 LB/HR	1.40	1.35
1,000,000 LLB/HR	1.75	1.65

Economics

As steam pressures and temperatures increase, so does the amount of kilowatts generated per pound of steam. Figure 6 illustrates this with different back pressures. Recent studies (beyond the scope of this

FIG. 6



TURBINE STEAM RATE vs. INITIAL STEAM CONDITIONS FOR VARIOUS EXTRACTION OR BACK PRESSURES

paper) have shown that with the current market conditions for oil and hog fuel, power generation tends to favour the highest steam pressure and temperature conditions commonly used, namely 1500 psig 950°F.

The balance of plant costs are impossible to generalize because of the infinite combination of cogeneration exhaust conditions and ratios of condensing to non-condensing power generation.

In steam generating plants, where the power turbine exhaust supplies the process steam of the plant and where there is not a multiplicity of turbines, it would be recommended practice to provide a pressure reducing and desuperheating station. This allows the process to continue with the use of purchased power during time periods when the cogeneration turbine generators are out of service for maintenance or repair.

Regenerative feedwater heating has been recognized as a method of reducing fuel consumption in steam power plants. In cases where partial condensing is used, studies have indicated that incorporating feedwater heating is economically advantageous and that the optimum condensing exhaust pressure is three to four inches of mercury absolute.

Conclusions

1. As primary fuel (natural gas, oil and coal) and purchased electric power costs increase, at a rate exceeding inflation, cogeneration will become economically more attractive.
2. In recent studies of cogeneration above 25 Mw sizes, steam cycle conditions of 1500 psig, 950°F appear economically the most attractive of the cycles studied.
3. The availability of byproduct fuels, from a process or on a purchased basis where they provide heat at significantly less cost than primary fuels, enhances the economics of cogeneration utilizing these fuels.
4. Unfortunately, it is impossible to generalize on the current economics of cogeneration using by-product fuels because of the large number of important parameters involved in an economic study. Such as:
   (a) electrical and standby power costs
   (b) fuel
   (c) ratio of process steam requirements to power requirements
   (d) exhaust conditions required
   (e) ratio of condensing to non-condensing power
   (f) size of plant
5. Under current economic conditions where power capabilities exceed 10 Mw, a study of cogeneration economics is warranted.

Discussion:

By-Product Fuels for Use in Cogeneration System

R.D. WINSHIP, *Combustion Engineering*

Question: Mr. Newby, *Canadian Boiler Society*

May I be permitted a couple of comments instead of a question for the same price. The first one is that Mr. Winship's point concerning mechanical drive turbines is very appropriate and dear to my heart. I think as the price of power goes up, it's going to become a lot more dear to a lot more hearts too. The basic attraction of course is the fact that you aren't penalized by the drop in the efficiency of the electrical conversion in both the generator and the transmission and the motors and so on.

The are a couple of cautionary points though. One is the fact that if you're talking of mechanical drive turbines up around 25,000 - 30,000 horse, such as Westinghouse had sold to Dow and so on, this is a sort of different animal in a lot of ways from the multitude of smaller ones that you run into in some industries, in that a big one like that is going to get the proper attention to the piping design and to the maintenance. When you get into a large complex, such as a paper mill, that uses a number of turbines then life gets hairier because of the fact that first of all, the maintenance has to be good, and secondly, the piping design becomes critical, and the larger the complex, the more difficult it is to maintain control of piping design. I have seen two cases where a 2,000 hp paper machine drive was pushed off its feet by too tight piping, and I am aware of many cases where a chipper drive of some 15,000 hp, the thrust was sufficient to break the feet. This is the kind of thing which gets very difficult to control, and it is worth a caution.

The other point that Mr. Winship's comment brought to mind was the fact that I wasn't thinking fast enough when the gentlemen queried the practicality of, in the case "B" of putting in a higher pressure boiler than the existing one, in that you could presumably wind up with a power boiler of 1,250 lbs operating with a recovery boiler at the 600 lbs. One of the major concerns there is the complications in the turbine generator, in that the new boiler would have to be in the inlet, and for the 600 lb you would have to have a second inlet, and then if the power boiler shouldn't be operating, then you have got a problem possibly with cooling the upper level. Life gets very hairy in a relatively small plant where you are mixing pressures.

Question: G. Lewarne, *Morris, Wayman Ltd.*

Yes, first of all, thanks to Mr. Newby for answering that question that I asked him before. This question

now to Mr. Winship is sort of in conjunction with what Mr. Newby just answered.

You have mentioned that it's very difficult and very corrosive to produce steam conditions above 825°F for black liquor, and it seems to me that most pulp and paper companies that are going to do cogeneration will have a recovery boiler and a power boiler, and if you want to take advantage of the 15,000 psi and the 950°F, there's a problem there. Have you done any design consideration of cleaning out the corrosive elements within the boiler before you put it into the turbine or is that not possible?

Answer: Mr. Winship

The nice thing about me, is that I always give the turbine a nice uniform product and if not, it's a constant low corrosive potential. The problem I was talking about was on the gas side, and there is two ways that have been studies to get around this. One would be to control the black liquor; take out the corrosive elements, as you have mentioned to control the sulphidity and remove the chloride. This adds to the cost of that, and it might be done.

Another thing that is being studied is, that we are looking at metallurgy or coatings which will allow us to go higher and have a more economic life to these things.

The final thing that has been studied over the last 20 years is generating in the recovery unit a higher pressures, taking the lower temperature steam and mixing it with steam from the power boiler they're usually about 50/50, and that way have a higher steam condition going to the turbines, so you generate your highest temperature steam in the unit where you have no gas site corrosion. Although this has been obviously thought of for many years, I can't think of any installation in Canada where it's in service.

Question: G. Sigal, *Shawinigan Energy Consultants*

Dave, I noticed you had to simplify in your efficiency the assumption on the steam generator. You assumed 75%. Could you tell me whether that steam turbine or that efficiency includes losses for the turbine generator and whether this steam turbine is a back pressure or single extraction and so on?

Answer: Mr. Winship

Yes, now that's the turbine generator efficiency, I took this from a paper that's 25 year's old. That's just the turbine generator losses, and that's put on a constant value and doesn't include any boiler efficiencies, and it happens to be used for both condensing and non-condensing turbines. The 75% was an arbitrary choice used for all turbines shown on that slide, some of which exhausted at 150, some at 50 and some at 2 inches. Yes, that's right, it include the generator as well.

Question: Ralph Lawton, *CIL*

I haven't heard mention of coal oil slurries as a possible feed. I would like to know where the state of the art is in that?

Answer: Mr. Winship

Well, you have got to ask yourself the question of why you want to burn a coal oil slurry. You fall into several categories here.

If you have equipment which was originally purchased or going to be purchased for coal firing then there's no point in burning a coal oil slurry because you can burn 100% coal and if your idea is to displace oil, there is no need to look at a slurry.

The other time would be if you have bought a boiler for burning oil only, and for some reason either the cost of the oil or the non-availability of supply is the problem, then you might want to look at a coal oil slurry, however your unit, as my friend says, for oil firing has a very high velocity through the generating bank. It has inadequate soot blower coverage, it has no provision for dragging the ash out at all for appropriate stages along the route, so if you go that way, you have to expect more frequent maintenance shutdown because you haven't designed to handle the high ash quantity you're going to get. You have to be very concerned with the plugging problems you're going to have, because the ash coming from the coal in the slurry, is going to probably (at anywhere above 50% load) be above its ash softening temperature. So fouling is the main problem, and whenever you do this, you're going to take a reduction in capacity on your unit that's quite significant. On any conventional oil or natural gas size unit you're going to take a very substantial reduction. It is being tested in Canada in one location, and there is government grant application for another larger location under consideration at this time. I can't get very enthusiastic about it myself. As I say, it's going to only be of benefit to a very small number of customers. Those who can't get oil or gas or some other suitable fuel for their unit, and coal is their only alternative.

I just thought of one more thing that I would like to say. Being lazy, and in my cost comparisons in there, I averaged lignite with bituminous coal and got sub-betuminus, so the numbers as you see in there were sub-bituminous coal.

Question: Gordon Robb, *Energy Mines & Resources*

After Dave's comments I can't resist the temptation to stir up a little enthusiasm for coal and oil slurry. Our department is helping fund tests on a boiler which was designed to burn coal in Chatham, New Brunswick, and the other larger test will also be on a boiler designed to burn coal, but to beginwith, the main thrust of energy policy right now is to reduce oil consumption, reduce dependance on oil. As most people are aware, in the mid-80's, (almost anybody who put the numbers together) the world producibility, the world demand situation sort of tightens up in the late 80's. There are a great many boilers certainly in the pulp and paper mills designed to burn bark or boilers which once burned coal, but there it is rather expensive to put in pulverized coal firing equipment. I see a fair amount of scope for coal-oil slurries strictly for oil displacement.

Then, I would like to ask Dave a question. You dealt with black liquor recovery boilers. If you were to put one in today, say in the Maritimes where co-generation is very important because the utilities are burning oil, with today's technology, what would you think would be the highest pressure temperature condition that you might attempt?

Answer: Mr. Winship

Personally I think I would look at a number between 850°F and 900°F. This is not in any way to say that we haven't sold units for much higher temperatures than this, but generally speaking, they are corroding with the rate we have predicted they would corrode, so it's a matter of the lifetime of your super heater, and again wiping out the chlorides or other unique impurities, the replacement time is still several years. It's a matter of doing a little economic study.

Question: Mr. Robb

Is that strictly a problem of super heater corrosion, or what about pressure which influences the metal temperatures in the boilers . . . ?

Answer: Mr. Winship

I have only been talking about super heater corrosion. There is also chemical recovery units. Two other areas in the furnace where usually there is additional corrosion and it's protected by pressure. Generally in the furnace, you don't have too much of a problem between 900 lbs, and when people go above 900 lbs and sometimes at 900 lbs, it depends on how conservation you are, you take some action to protect the furnace walls in these areas with either better metallurgy or coatings of some sort, and these today are pretty effective so you can certainly go to the 12,000 lb level. You will have maybe every second or fourth annual outage, you will have to go in and recoat your furnace locally, but it's still economic if you're looking at co-generation.

Question: Peter Zaharuk, *Falconbridge Nickel Mines*

My questions concern the process steam and the condensate return from processes. What precautions are necessary to protect the boiler plant or your power plant from contaminations of your condensate? Actually, the power plant operators in our plants are very reluctant to accept condensate from the processes, and what precautions did you take, or what would he have to take to accept this condensate?

Answer: Mr. Winship

Well, he's been trained as a good steam plant man, and if he's cautious, they usually like to reject all the condensate coming back, and this makes life easier.

There are a couple of things you can do. If you know what you're looking for, you can often have an in-line monitoring instrument that will tell you "yes, I have got a leak on one of the process fluids into the condensate" and then you just have a value which puts it into the sewer until you can correct that heat exchanger.

If it's copper or iron which is perhaps the most common one picked up from the heat exchanger surfaces themselves or the machinery surfaces where the condensing takes place, there is no on-line monitor that measures particulate iron, so you have to analyze for it, and we recommend on a weekly basis that this be done. Just as an aside, of course, the problems is much more severe after the shutdown because you have had all your heat exchanger surface open to the atmosphere, and you're going to bring back slugger corrosion products. If you bother to correlate failures in boilers, you will see that they almost always follow one or two days after a shutdown. We recommend that you analyze this on a weekly basis, assuming that you're running along smoothly, and then you can remove it by chemical cleaning, quite often called acid cleaning, on a regular basis. What we are saying is if it turns out that your acid cleaning frequency is greater than once every 1½ years, then today you can put in some sort of filter to take out these particulate matter. Generally, of course, you can either use low temperature filters which are very cheap and efficient, (but then you hurt you cycle efficiency because you have to drop all your feed water down to that temperature,) or you can use less efficient, higher filters. It's a matter of a little study, and what I am going to do is put a couple of papers which describe how this sort of study is carried out. I will put those as references to my paper. Not being a water treatment man, I wouldn't want to go too far in explaining all the ins and outs of this.

Question: G. Boucher, *Hydro Quebec*

Say, Mr. Chairman, I hesitated to raise my hand, but I was waiting for you. But with Mr. Winship's claims of purity, I don't even want him to listen to my question. So I'm going to address it to Mr. Rivers. Mr. Winship, however, gave us a table of relative costs of various temperatures and pressures for a 500,000 lb boiler. Now, he did say also that there is practically no difference for pressure, so does that mean that we can ask for a bid on a boiler? When we estimate, how high or how low should we go that we can manipulate their bid or the figure they give us and use those factors, forgetting all about pressure and only go by temperature?

Answer: Mr. Rivers

Can I respond to that one? I suggest you be very careful in terms of what the drum thickness is in these particular units.

Answer: Mr. Winship

All I can say is that from what I can see of those relationships he had 7% from one temperature pressure to another one, and he mentioned the same as we did that there is a big increase in the degrees of super heat. So, your super heater cost is higher and the costs of metals is higher and those relationships were relatively close from my one scanning of a percent difference, in about a 7% category. I thought they were related. I don't know if I have properly answered your question or not.

Question: Mr. Boucher

You're going to get the difference in 7% which is a lot of money.

Answer: Mr. Rivers

One change was 7%, in covering the whole range it was 27%. From what I could glance at, we will have to look at each other's figures later. These are in ratios. I have given you prices in a smaller area which are on an estimating basis that you would get any time by asking a consultant to give you some prices on 3 or 4 pressures and temperature and capacity sizes. This would be readily available. So, there they are for the sizes I thought you would be talking about in cogeneration (100 to 400.)

Answer: Mr. Winship

As I said, they include the labour. That is set on exactly the same basis as Mr. Rivers outlined.

A Gas Utility's View on Cogeneration

T. E. GIERUSZCZAK,
The Consumers' Gas Company

Invitation to Speak

Your program chairman, Mr. Alex Juchymenko of Ontario Hydro, invited Ted Creber, then president and chief executive officer of the Consumers' Gas Company, to speak to you at today's luncheon as a representative of a major fuel supplier in Ontario. Mr. Juchymenko indicated that you would like to hear from Mr. Creber regarding the outlook for Natural Gas supply and his thoughts, from a gas utility's point of view, on the potential for cogeneration in Ontario, as well as, in what way, if any, a gas utility might fit into the expansion of the cogeneration concept in Ontario. Unfortunately, Mr. Creber was unable to be here. He asked me to pinch hit for him and present his views on co generation to you.

In reviewing your program outline, I noted that you were exposed yesterday in your sessions to a number of conceptual considerations on cogeneration. Today, you have been exposed to cogeneration technological developments, a subject on which I profess to know very little. I do, however, know that energy supplies are limited, that energy could become a more scarce commodity in the future if we don't do everything in our power to conserve our resources, to utilize them in the most efficient ways available to us and to continue to search for new sources of supply.

The Energy Crisis

What is the nature of the energy crisis that we have heard and read so much about since the OPEC embargo imposed in October 1973, and about which we read and hear more and more?

Basically, I'm sure you all appreciate that there is no shortage of energy resources world-wide. The problem is not only one of Geography but also of Politics. The Organization of Petroleum Exporting Countries (OPEC), particularly Saudi Arabia and Iran, have until recently had 85% of the free world wide oil reserves outside of the United States and Canada. Recently reported oil discoveries in Mexico will undoubtedly change this oil scenario to some extent.

Substantial reserves of Natural Gas exist in Russia, the Middle East and Africa. These reserves are, however, far removed from the major markets — Europe, Japan and the United States.

The OPEC Embargo, the subsequent unprecedented increase in oil prices, the natural gas shortage in the United States, brought about mainly by The Federal Power Commission controlling fuel prices at unrealistic low levels, all have brought sharp focus on the growing shortage of cheap and I underline the word cheap, energy.

The OPEC Embargo has caused a rude awakening to the fact that our western society was accustomed to having cheap and abundant energy resources. It brought int sharp focus:

1) The extent to which we wasted enormous amounts of energy.
2) The fact that world supply of oil and natural gas was not going to be able to continue to meet the growing world demand for these heavily used, diminishing and increasingly more expensive energy resources.
3) The need for a comprehensive national energy plan fully integrated with an industrial strategy to circumvent jeopardizing our national security and risking economic social and political dislocations in the relatively near future.

What has changed since early 1974, just shortly after the Embargo? The world price for oil has quadrupled! Industrial energy costs have tripled!

Higher energy costs have caused a world recession. Inflation and high unemployement!

Canadian Natural Gas Production

What is the position of natural gas in this energy Scenario, in other words, how has the natural gas industry been affected by these world events?

Virtually all the production of natural gas in Canada occurs in the Prairie Provinces and British Columbia, with small quantities being produced in New Brunswick and the Northwest Territories as well as in Southwestern Ontario. More than 75% of Canada's marketable proven reserves are in Alberta. In the past 8 years substantial reserves of natural gas have been discovered in the MacKenzie River Delta, the Northwest Territories and in the Canadian Arctic Islands, yet undisclosed commercial volumes of natural gas have also been discovered off the East Coast of Nova Scotia and Newfoundland.

What about the potential for gas production in Ontario? Despite gas being discovered and produced in Ontario since the last decade of the 19th century, discoveries to date have been from relatively shallow formations and, although significant in local terms, have now become relatively insignificant in terms of total provincial needs. Consumers' gas currently obtains about 1 1/2% of its requirements from local production, including the offshore production from Lake Erie and obtains the balance from Alberta. Alberta is also the major source of supply for the other major Ontario distributors.

I am sure that it is of interest to all of you that it was thought as recently as 2½ years ago that only frontier areas of Canada would be able to supply new reserves in sufficient volume to meet future long-term market potential for gas and that the situation has changed to such an extent that it is now the generally accepted view that supplies from the traditionally producing areas in Western Canada are adequate to meet Canada's requirements into the late 1980's and perhaps into the 1990's, and with frontier reserves, adequate to meet Canada's requirements to at least the turn of the century.

Natural Gas Surplus - Oil Deficiency

Although there is currently a surplus of natural gas in Canada, Canada at present is a net importer of oil with 20% of its requirements currently being supplied from offshore. This position is not likely to improve before at least 1985, if at all, in fact one OPEC spokesman predicts a disastrous energy shortfall in the late 1980's unless there is a smooth transition of the world from an oil-dominated economy to a new era in which other sources of energy will assume their righful share in the market. On the other hand, there is at least one energy specialist that strongly disagrees with this viewpoint. He claims that, with trends to lower annual growth rates in oil consumption, the production of oil could continue to increase for almost another fifty years - to about the year 2025. Although he claims that there are at least two generations available to us to undertake the necessary research and development on alternate sources of energy, it is quite clear that new technology and new energy resources will be needed in the years ahead.

With the surplus of natural gas that is likely to continue into the next century, and the projection that Canada will be importing one-third of its oil requirements by 1985, Consumers' Gas strongly supports the substitution of natural gas for oil wherever practicable to minimize dependence on offshore resources and to stretch out the life of a more rapidly depleting non-renewable natural resource.

Alternative Energy Developments

Although consumers' gas is primarily in the gas distribution business, it considers itself an energy company. We are in the business of providing a primary source of energy to all segments of the markets we serve. We have a growing awareness that the energy Scenario in the future will be significantly different than that in our recent past. Conventional supplies of energy will become scarce and expensive. Consumers's gas thus must keep a close watch on alternative energy developments.

Consumers' recently completed a reappraisal of alternative energy developments. Neither liquefied natural gas nor synthetic natural gas are cost competitive with natural gas from Western Canada but may be cost competitive with frontier gas supplies when they became available. There is limited potential for exploitation of geothermal areas and geopressured zones in Canada. The hydrogen economy is not expected to be economically viable until hydrogen can be produced from off-peak power generation by fusion reactors. This will not likely be before the year 2000.

The prospects of economic viability for the utilization of gaseous fuel from biomas appear slim for the foreseeable future.

Solar Energy

Some proponents stongly suggest that, to find new energy in the magnitudes ultimately required, solar power is the ultimate solution. Technology is available for using solar energy to heat and cool residential and low rise commercial buildings but such systems are yet some way from being economically feasible on a broad scale.

Other Alternatives

What about nuclear breeders and nuclear fusion, magnetohydro-dynamics, tidal power, ocean thermal energy conversion and wind energy?

Nuclear breeder reactors which can produce their own fuel and extend the life of our uranium reserves are not likely to have commercial application until near the end of this century.

Nuclear fusion, the harnessing of the power of the hydrogen bomb, is still in the laboratory development stage. Fusion technology is not likely to be commercialized until well into the 21st century.

Keeping in mind the engineering and scientific problems, commercialization of magnetohydrodynamic technology on a significant scale is not likely to take place before well into the next century. Potential use of tidal power is limited to the Bay of Fundy in Nova Scotia. Ocean thermal energy conversion, the recovery of solar thermal energy stored in the ocean, is technically feasible although the state-of-the-art in heat exchangers and submarine electric cables needs to be extended and proven in an ocean environment. Production of electricity from wind energy is technically feasible, however, wind as a source of energy, will most likely have little significant impact on the total energy scene.

Near Term Solutions to the Energy Problem?

Although Canada as a whole is considered rich in resources including hydrocarbons, Ontario has to rely upon Alberta and the U.S. for a substantial portion of its energy requirements. Ontario is, however, blessed with good reserves of uranium and thus must rely heavily on nuclear energy in its future energy planning.

Are there then any nearer term solutions to the energy crisis?

Conservation

Conservation of energy, not abstinence from its use, is the key factor fending off an energy crisis. Waste in the consumption of energy has to be reduced. There are many areas where energy can be conserved without impairment of economic growth. Consumer' gas, on its own initiative, embarked on a conservation program through the promotion of home insulation. This was some time before the federal government got involved in its programmes to conserve energy through incentives to homeowners.

Consumers' gas has assisted the division of industry of the Ontario Ministry of Industry and Tourism in the setting up of its energy bus. I & T has made available to industry a mobile mini-computer with engineers trained to analyze energy usage and needs at individual plants. The director of the technology branch of the division of industry firmly believes that at least 10% savings on industrial energy requirements can be achieved through proper energy management. Some firms have achieved a saving of almost 30% over four years.

With the impending decline of availability of fossil fuels conservation can play a very important role to stretch out the life of our fossil fuel and nuclear reserves.

District Heating

Another near term partial solution to Ontario's energy needs is district heating. There is a great likelihood that district heating does have a place as an energy source in helping to meet Ontario's future energy requirements because of the tremendous amounts of waste heat being generated at Ontario's nuclear plants. Consumers' gas as a utility would like to see demonstration projects proceeded with so that the relative economics of one form of energy used over another can be demonstrated and found out through practical application.

It is our opinion that the private sector has a place in such demonstration projects. It is our opinion that a utility such as Consumers' can bring to such a project a different outlook which can produce the type of ultimate planning for district heating that would be desirable for the province.

Consumers' gas is currently carrying out discussions in relationship to the utilization of waste heat from the Pickering Nuclear Power Plant for use at the proposed new community of North Pickering, as well as the utilization of waste heat for the Bruce Nuclear Power Plant For Agriculture (Greenhouse Operation) and Aquaculture (for fish farming and fish production for stream and lake stocking).

Energy from Solid Waste

With the increasing difficulty to find accessible landfill sites, serious considerations have been given to feasible alternatives for solid waste management, one of which is its utilization as a fuel. The most promising short term approach to recovering energy from wastes appears to be direct combustion. By this process, steam and/or electrical generation has been practiced for many decades in Europe; the practice in the U.S. and Canada is of relatively recent origin. I am sure you're all familiar with the Ontario Ministry of the Environment Energy Recovery Plant in Downsview, metro's "Watts from Waste" project, and Mississauga's solid waste disposal energy producing proposal. Economic viability of these schemes has yet to be demonstrated.

Cogeneration

Now what about the energy option that is germaine to your seminar, Cogeneration? I have perhaps taken a circuitous route to set the stage for my exploring this subject with you but feel that such an approach was needed to put it in proper perspective. It is an energy option which has to be fully explored and this seminar is just another necessary step in the exploration process. Is it a cost effective option?

The term Cogeneration, as you all know, applies not only to dual energy use systems (simultaneous generation of power and heat) but also includes combined cycle operations.

The total energy concept is also a form of Cogeneration that the gas industry has promoted for the past decade and a half.

Cogeneration has been practised in Europe, the U.S.A., and Canada for a considerable time. The technology is well established and steady progress is being made in improving the efficiencies of Cogeneration plants to make them more economically attractive.

Cogeneration in Europe

While Cogeneration has steadily declined on the North American Continent, it still plays a major role in

Europe. Existing plants are being modernized and new facilities are under construction. Cogeneration presents a healthy stimulus to the economy since it provides a market for construction firms and equipment manufacturers, and thus is a subject of substantial governmental and industrial R & D.

The key to Cogeneration development in Europe has been a cooperative industry-government-utility effort. Such cooperative effort can do much to effectively reduce the constraints on Cogeneration.

Some of the factors which contribute to a continued presence of Cogenerative systems in Europe are the following:

- Generation of electricity in industrial operations and established wheeling practices.
- The access to a European gird and the function of large utilities as power brokers.
- Increasing availability of Natural Gas.
- District heat as a source of revenue for utilities.
- Recognition of the importance of load management.
- Modularization and standardization of turbines for district heat and industrial applications.

In Europe gas turbines are very popular for supplying electricity and district heating. The coupling between heat generation and electricity supply is less rigid than in a steam turbine, which permits flexible operation over a wide range of demand situations. It has the added advantage that within city limits it will not pose environmental problems.

Cogeneration in Ontario - Advantages & Disadvantages

It should be quite obvious to all of us that Ontario has all the necessary ingredients that are needed for Cogenerative systems to survive. But what are the advantages and disadvantages to Cogenerations? The incentives for on-site power generation with process heat are:

- Doubling plant energy use efficiency
- Conserving energy resources
- Lessening electric utility system load and freeing more power for other system users.

Looking at the other side of the coin the drawbacks are that:

- Present power plant engineering is limited by the steam cycle and the physical size of many plants.
- Cogeneration can impose constraints on operational flexibility.
- Capital costs are high in relation to the economic yield.

It would appear to me that under today's energy Scenario, there is a great potential in Ontario for Co generation.

Virtually every major process plant in Ontrio has the potential to produce electric power as a byproduct of the steam generation required for it processes. Co generation could greatly improve such a process plant's overall energy efficiency, reducing total fuel consumption, without impairing the plant's productive output. Food and beverage industries, distilleries, chemical, paper, refining, steel and textile industries and industrial parks would appear to be prime targets for expanding use of Cogeneration in Ontario beyond the 12% of the some 5000 Mw industrial load currently in use.

According to a report on "Industrial By-Product Power" prepared by Leighton & Kidd Limited in May 1977, the maximum potential in Ontario, if all industrial steam plants were modified to produce by-product power, was estimated at 3000 megawatts of capacity increasing to about 4400 megawatts by 1985.

The report concluded that:

"Physical, economic and institutional constraints preclude realization of this maximum potential and under present circumstances it is estimated that Ontario's complement of by-product power plants will grow at a modest rate."

But the report also concluded that:

"A joint program by industry, Ontario Hydro and the province might be fashioned to accelerate this development."

The report also points out that:

"A possible target for such a program would look to installing an additional 1500 Mw to bring the total installed capacity of industrial plants up to about 2000 Mw by 1985."

Such a target for increased industrial by-product power production could increase oil and/or natural gas consumption in Ontario by eight million barrels oil equivalent (45 BCF natural gas equivalent) annually, while reducing Ontario Hydro's coal imports by four million tons annually. This would result in a net reduction in Provincial imports of fossis fuels of about $100,000,000 annually, basically from the U.S., which would also serve to improve our national balance of payments.

Consumers' Interest in Cogeneration

Why should a natural gas distribution utility like consumers' gas be interested in promotion of Co generation? For several reasons:

1. It is interested in, and actively participating in, promoting, energy conservation.
2. It has an assured gas supply likely to the turn of the century, a gas supply which is likely to be priced at a competitive advantage over oil for some time to come because it is a less scarce commodity and is likely to remain so for some time.
3. The price of gas is likely to remain relatively stable compared to electricity although tied to oil prices in Canada which, in turn, will be tied to U.S. and world oil prices.
4. With the price of electricity doubling in the past 5 years, the prospects for using gas turbines for Cogeneration are enhanced.
5. Consumers' considers itself an energy company with positive interests in energy forms other than natural gas - it has a high equity interest in Home Oil Company - and a declared interest in

exploring the merits of district heating as previously noted.

6. Consumers' is willing to explore joint venture possibilities including participation in co generation projects within its market areas. Symbiosis between public utilities and private industries is not without precedent and Consumers' is ready, willing and able to participate in any energy scheme that has a potential for economic viability.
7. Consumers' believes in the responsible use of energy, i.e., the cost effective utilization of energy no matter what the source - Coal, Oil or Natural Gas.
8. Consumers' can accept the fact that federal and provincial governments will continue to have a major role in regulating energy prices and supply.

In my opinion industry, government and the electric and gas utilities should use their imagination and work closely together to develop a program to facilitate accelerated development of industrial by-product power. It is interesting to note that utility attitudes about Co generation are changing from past policies of high charges for tieing into the system and for purchasing peak power and from a reluctance to buy excess power for anything more than give-away prices. Electric utilities in assessing the merits of Cogeneration must compare the cost of Cogenerated power not with their average cost per kilowatt hour but with the cost to produce power from new electric power plants. They should continue to be encouraged to sitting down with industry to mutually solve energy problems.

Consumers' gas is also interested in participating in any such dialogue in its market area.

Actions Needed

Summarizing, the following actions are needed to accelerate the development of Cogeneration:

By Industry

- Involve and be willing to negotiate with utilities
- Accept government role
- Increase awareness of technical/economic/ownership options
- Evaluate higher energy prices in return on investment assessment.

By the Utility

- Be willing to negotiate with industrial company
- Accept government role
- Compare Cogenerated power costs per KWH with power costs per KWH of new electric power plant
- Consider small plants if cost per KWH is competitive
- Calculate stand-by rates on basis of total number of industrial in-plant power plants i.e. take into consideration diversity factor.

By Government

- Provide financial incentive
- Provide technical assistance
- Balance energy and environmental policies
- Clarify jurisdiction and provide regulatory exemptions for Cogenerators.

No Single Solution

In conclusion I would like to again point out that the days of cheap energy are long gone. To extend the life of our energy resources, energy conservation is here to stay. No single energy source will solve our energy problems - All energy alternatives will have to be resorted to, including Cogeneration.

Gas Turbine and Its Economics

R. J. NEARY
Solar Turbines International

Commercially available high-performance industrial gas turbines can achieve a heat rate of 5630 BTU/Kwh and energy-to-steam ratios of 207 Kwh/10 million BTU. It would appear that successful developments in this technology, coupled with viable economics, could be of substantial significance. The effect of changing markets and economic conditions is evaluated in this paper and specific examples are presented to illustrate the increasingly favourable climate for cogeneration systems in today's energy conscious society.

Cogeneration Systems

Definition

Two years ago, when "COGENERATION" became a popular term, there was much confusion as to what exactly Cogeneration meant.

A consensus of recent definitions from industrial societies, gevernment agencies, legislation and energy studies gives the following definition:

> Cogeneration is the sequential use of energy to simultaneously produce either electrical or shaft power and usable process heat.

This definition would include all systems which used to be referred to as "TOTAL ENERGY" as well as those that only assume a portion of the heat and/or power requirements of a facility. It would include systems which are electrically intertied to the utility grid as well as those which are electrically isolated. It would include steam systems with Rankine cycles, as long as the steam is condensed in the process heat load and not in a surface condenser.

Why Cogeneration?

Many countries now find themselves in the position where imports exceed exports. Energy may be a large import item, or they may be able to export energy they conserve and improve their balance of payments. Accordingly, most of these governments have looked at cogeneration and are trying to stimulate the use of it to conserve energy.

Without the active support of government and the electrical utilities, cogeneration stands little hope of making a significant contribution to an energy conservation plan.

Type of Cycles

There are basically two types of cycles. One type is "topping cycles," in which the fuel is burned to produce electricity and the exhaust heat is used in the process. The other type is "bottoming cycles," in which fuel is burned for process heat, such as smelting or kiln baking, and the exhaust heat from the process is used to generate electricity. Where heat is available for a bottoming cycle, electric generator sets can be supplied for $600 to $750 per kilowatt and operating costs are negligible. For either topping or bottoming cycles, the return on investment is calculated the same way.

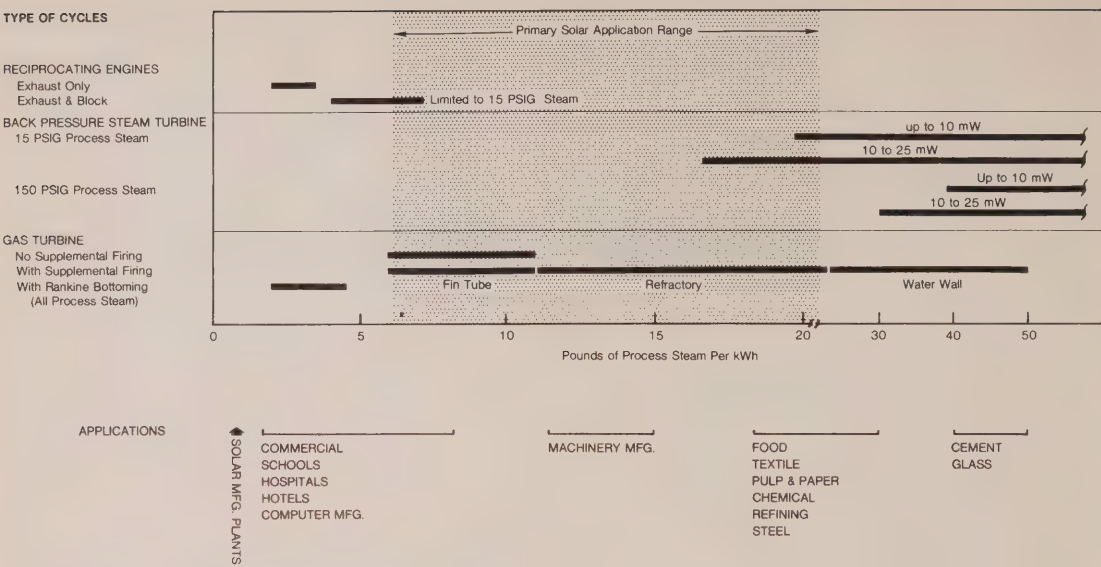
In a topping cycle, there are basically three types of drivers to consider. Each fulfills an appropriate application with inherent flexibilities and limitations, as shown in Table 1. Solar manufactures gas turbines which are limited to topping or combined cycles.

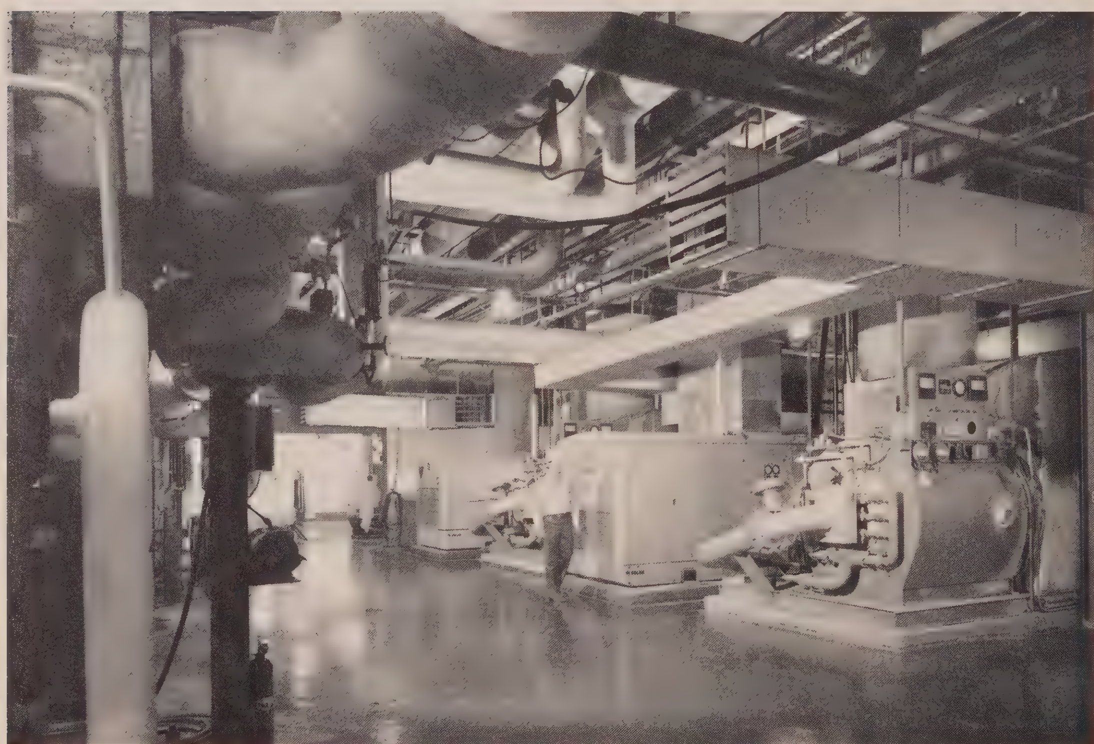
Alternatives to Utilities

There are basically two different ways in which an electrical utility and an industrial user can participate in a cogeneration activity. Each alternative has advantages and disadvantages and it is important that both be considered for each individual application to be certain that the utility and the industrial customer take advantage of the appropriate arrangement.

The first alternative is for the electrical utility to own and operate the cogeneration facility. The electrical generation equipment is then tied directly into the utility grid and the equipment can be operated to satisfy the heat requirements of the industrial customer. The facility should be located close to the industrial customer to save on the transport of process heat. The industrial customer then continues to buy electrical power in the usual fashion, but he also purchases the process heat (usually in the form of steam) from the utility. The industrial customer typically will be able to purchase this process heat at a lower cost than if he

Table 1. Comparison of Cogeneration Potential





The ultra-modern Oral Roberts University in Tulsa, Oklahoma generates its own electrical power using seven Solar Saturn generator sets. Exhaust heat from the turbines is used to provide refrigeration and hot water heating.

produced it himself, and he does not bear the capital cost of the boilers. This would be particularly significant for a new industrial operation where the customer has not yet purchased his boiler or in an old operation where existing boilers need to be replaced.

The second alternative is for the electrical utility to furnish an intertie to a system owned and operated by the industrial heat user. As previously stated, this intertie would improve both the capital cost to the industrial user and allow him to operate at an optimum cycle efficiency. The electrical utility benefits by getting additional generating capacity without the problems associated with raising capital, siting the system, and overcoming environmental objections.

Solar's Experience

Solar Turbines International has been furnishing cogeneration systems to the process industry for more than 17 years. There are over 280 Solar turbines in this type of service and they have accumulated over eight million operating hours. Some of these packages have operated in excess of 100,000 hours. Our largest installation includes 12 turbine generator sets at a single location. Another single-site installation has two generator sets, two natural gas compressor packages, and three mechanical drive refrigeration packages.

How a Turbine Works

A gas turbine engine consists of a compressor, a combustor, and an expansion turbine (Figure 1). Ambient air is drawn in through the compressor and flows steadily into the combustor (Figure 2). Fuel is fired in the combustor and the resulting, high-energy hot gas passes through the expansion turbine. The energy extracted through the turbine section is used to drive the compressor and the load.

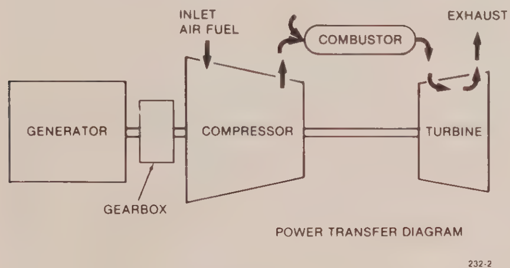


Figure 1. Basic Simple Cycle Gas Turbine

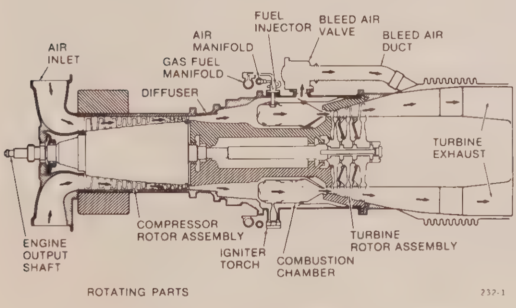


Figure 2. Airflow Through Typical Axial Turbine

Burning is continuous in the combustor, so temperatures in the turbine section are maintained by controlling the fuel-to-air ratio. Most industrial gas turbines use from three to four times as much air as is required to combust the fuel. Consequently, the exhaust stream contains 15 to 20 percent oxygen, so it is possible to burn additional fuel in the exhaust stream to increase the amount of thermal energy available. Since the exhaust is clean and and dry it can also be used directly as hot air for drying or curing.

Solar manufactures three industrial turbine engines which can be used in cogeneration topping cycles (Figure 3). These engines are available in complete generator, compressor or mechanical drive packages capable of driving type of customer specified equipment.

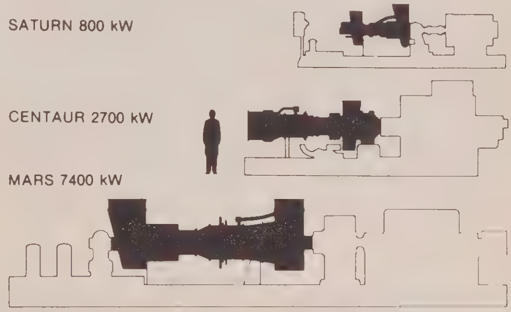
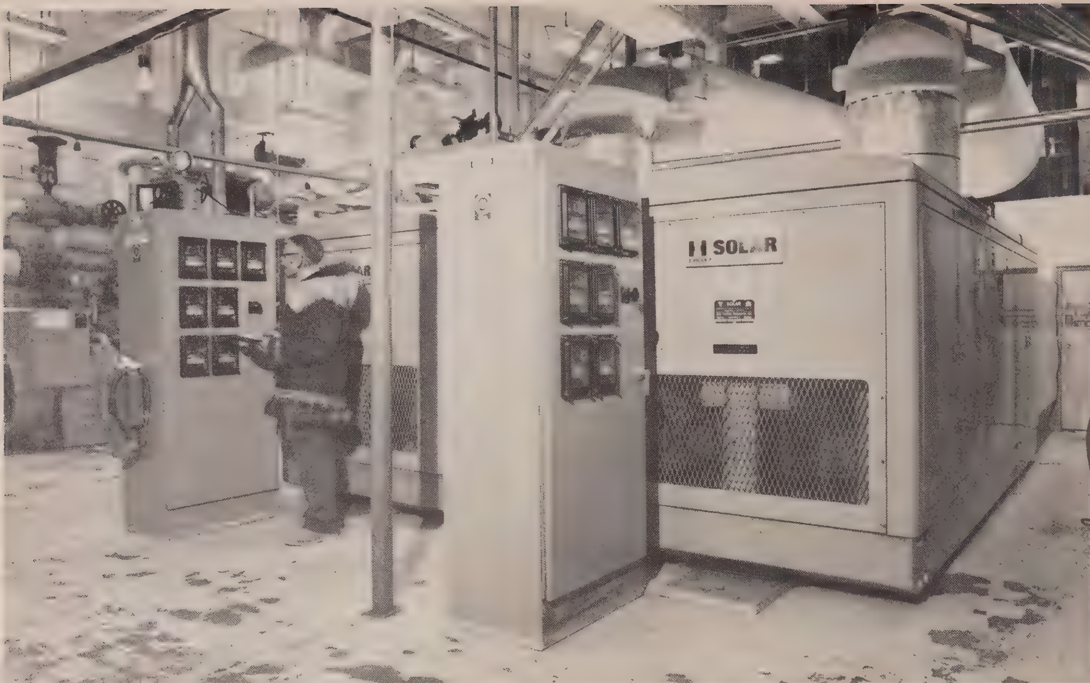


Figure 3. Solar Gas Turbine Generator Sets

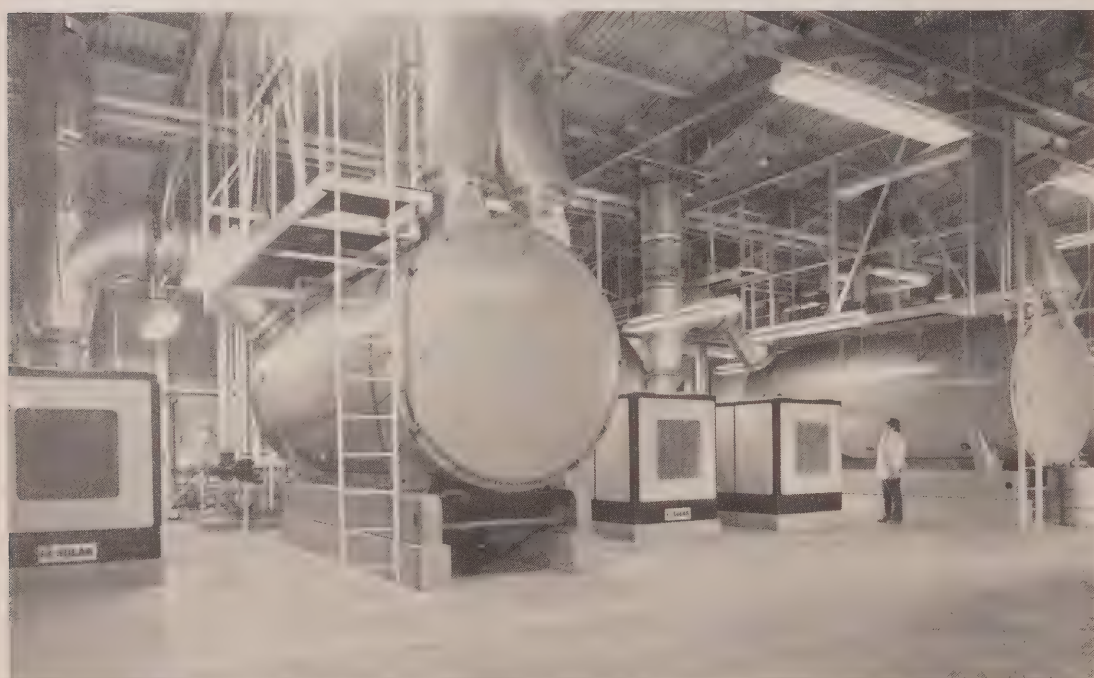
Exhaust Heat Utilization

There are three distinct methods of utilizing gas turbine exhaust heat. Fuel burned in almost any industrial process can be credited totally or partially by one of these methods:

- The most common procedure is to pass the exhaust flow through a heat exchanger (or boiler) and transfer its heat to a process fluid or gas such as H_2O, air, or oil (Figure 4). Since the exhaust gas contains over 16 percent oxygen, additional fuel can be fired in the exhaust flow to achieve higher initial temperatures or increased energy as required by the particular process. A number of manufacturers offer these types of heat exchangers and boilers as standard product lines.
- A second common method is to use the exhaust flow, which is relatively clean and dry, as a direct-heating and/or drying medium (Figure 5). The exhaust flow can be diluted with ambient air to achieve any lower temperature and increased volume flow desired. If the process back pressure is low, this can be done with a simple inductor. At higher back pressures, a fan is required to provide the dilution air. As in the case above, additional fuel can be burned in the exhaust prior to process use to match any temperature/energy requirement.



All electrical power for the village of Barrow, Alaska is supplied by two Solar Saturn gas turbine generator sets. The exhaust heat is used for heating several public buildings.



Four dual fuel Saturn gas turbine generator sets with a 2900-kilowatt capacity provide power for the Naval Arctic Research Laboratory at Point Barrow, Alaska. Exhaust heat is directed to boilers, the water heated to 240°C and pumped throughout the camp.

- A third method, which is requently utilized in the oil and gas industry, is to use the exhaust flow as highly preheated combustion air in devices such as boilers, space heaters, oil heaters, and hot gas generators (Figure 6). This is the most efficient method of exhaust utilization since all of the exhaust energy above ambient can be credited to fuel saved in the combustion device.

General Performance

The values shown in all three examples (Figures 4, 5, and 6) are based on the following assumptions:

Ambient conditions	- sea level and 60°F
Fuel	- liquid or gas
Load	- 100 percent

Steam data:

Condensate return	- 200°F
Steam conditions	- dry and saturated
Boiler efficiency	- 80 percent

For altitudes other than sea level, read the correction factor from the following table, and multiply power output, fuel consumption, and mass flow by the factor. For part-load conditions and other ambient requirements, please contact Solar. The constants shown in these examples can be used to perform a similar preliminary energy balance for other types of systems.

Altitude (ft)		Factor
	0	1.000
	2,000	0.930
	4,000	0.864
	6,000	0.801
	8,000	0.743
	10,000	0.688

Evaluating the Benefits of a Solar Cogeneration System for Your Application

Return on investment in a cogeneration system can be determined by considering four primary and two secondary variables. The primary variables are:

- Utility Electrical Rate ($/kWh)
  This should be a composite rate including energy charge, demand charge, and taxes as applicable. If a declining rate structure is in effect, it should be taken into account. This information can be obtained from your utility bill and a rate schedule available from the utility company.
- Annual Utilization (%)
  Like any other capital investment, return improves with higher utilization. Maximum utilization can be achieved by generating the required base load while in parallel with the electrical utility, which would provide peaking and standby power as required.

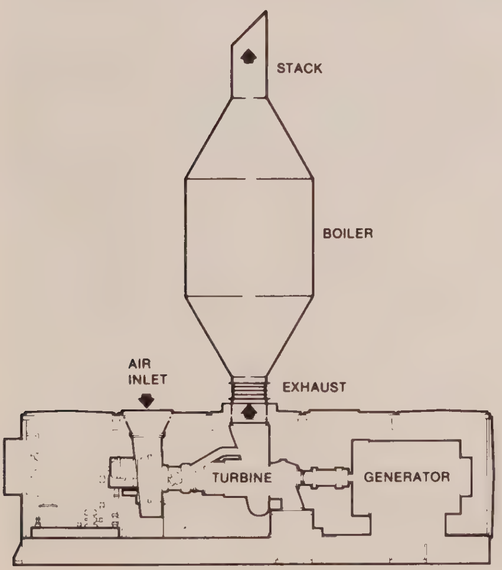
$$\text{Annual Utilization} = \frac{\text{Annual Hours of Operation}}{\text{8760 hours/year}}$$

- Fuel Cost - $/Million Btu ($/mm Btu)
  The net cost of onsite generated electricity will be directly proportional to cost of fuel used. Cost is expressed in $/million Btu as a convenient form for the necessary calculations. It can be determined as follows:

Number 2 Diesel
Heating Value = Approximately 130,000 Btu/gal
Cost = 0.363/gal

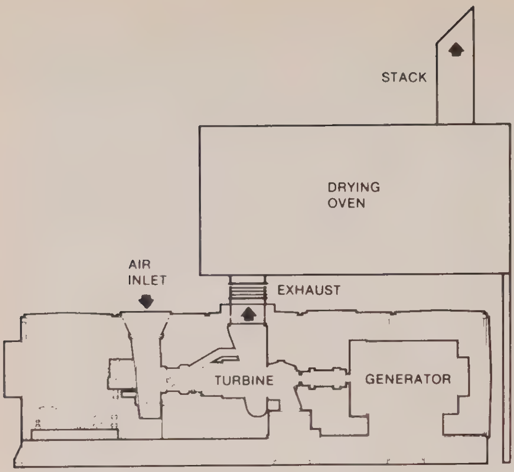
$$\text{\$/mm Btu} = \frac{1{,}000{,}000}{130{,}000}(0.363) = \text{\$2.79/mm Btu}$$

Natural Gas
One Therm = 100,000 Btu
Cost = 0.18/therm
$/mm Btu = 10 x 0.18 = $1.80/mm Btu



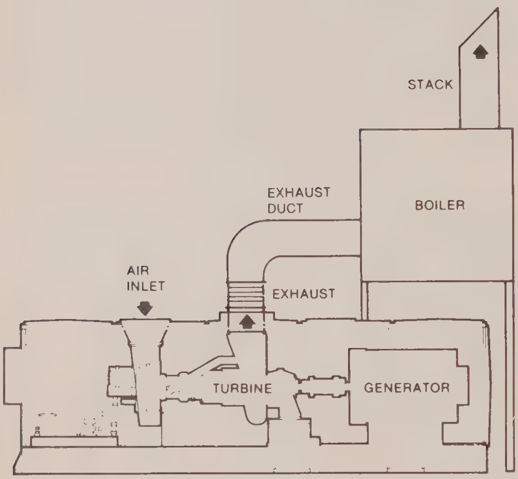
	Saturn	Centaur	Mars
Stack Temperature (°F)	300	300	300
Steam Output (lb/hr)	6425	17,886	32,913
Exhaust Temperature (°F)	848	836	774
Fuel Input (million Btu/hr)	13.22	39.84	82.03
Electrical Output (kW)	800	2628	7209
Air Mass Flow (thousand lb/hr)	49.20	140.0	291.2
Net Fuel Rate (Btu/kWh)	6524	6685	5694

Figure 4. Unified Turbine Exhaust Used to Produce 15 psi Steam



	Saturn	Centaur	Mars
Heat Credit (millions Btu/hr)	9.14	27.27	52.70
Exhaust Temperature (°F]	848	836	774
Fuel Input (million Btu/hr)	13.22	39.84	82.03
Electrical Output (kW)	800	2628	7209
Air Mass Flow (thousands lb/hr)	49.20	140.0	291.2
Net Fuel Rate (Btu/kwh)	4361	4783	4113

Figure 5. Turbine Exhaust Used Directly as Hot Air Source



	Saturn	Centaur	Mars
Stack Temperature (°F)	300	300	300
Steam Output (lb/hr)	48,050	135,508	276,717
Additional Fuel (million Btu/hr)	49.2	139	287
Exhaust Temperature (°F)	848	836	774
Fuel Input (million Btu/hr)	13.22	39.84	82.03
Electrical Output (kW)	800	2628	7209
Air Mass Flow (thousand lb/hr)	49.20	140.0	291.2
Net Fuel Rate (Btu/kW)	4361	4783	4113

Figure 6. Turbine Exhaust Used as Combustion Air in 200 psi Boiler

- Installed Cost of Cogeneration System ($/kW)
  Precise estimates of system installed cost must be made on a case-by-case basis because of variations in such factors as site conditions, local labor costs, and heat recovery equipment used. However, for purposes of an initial economic analysis, the following average values of total installed cost can be used.
  Saturn $480/kW
  Centaur $400/kW
  Mars $300/kW

The secondary variables are:

- Net Fuel Rate for Onsite Generated Electricity
- Fuel rate for a generator is expressed in terms of Btu/kWh, i.e., the number of Btu's of fuel input required to produce one kilowatt for one hour. In order to find the incremental fuel required to produce the electricity above the fuel needed to satisfy the process heat requirements, we credit the fuel used by the gas turbine with the fuel that would have had to be used to satisfy the process heat requirements. (In calculating fuel credit, one must take into account such factors as boiler efficiency so that actual fuel required to satisfy the process requirements is determined.) When this value of incremental fuel is divided by the number of kilowatts produced, the result is a quantity defined as Net Fuel Rate (NFR). In equation form:

$$NFR = \frac{\left(\text{turbine fuel} - \text{fuel value of heat recovered}\right)}{\text{kW output}}$$

Net fuel rate will vary as a function of the type of heat recovery system and average kW output, but typical values will range from 4000 to 6000 Btu/kWh, which is less than 50 percent of the fuel required by the utility. For an initial evaluation, an average value of 4500 Btu/•kWh is satisfactory.

- Maintenance Cost
  Maintenance cost should be considered in calculating net cash flow, but has a relatively minor impact. Typical maintenance costs are expressed in ¢/kWh and vary in the range of 0.18¢/kWh, depending pirmarily on the operating cycle. Frequent starts and stops will result in higher maintenance cost while continuous operation will result in lower maintenance cost.

Application and Evaluation

The application and evaluation procedure can be best aillustrated with a specific example.

The values used in this analysis are approximate but are intended to represent costs for Solar equipment delivered and installed in eastern Canada. Fuel costs, taxes and utility rates also represent local conditions.

The values used are:

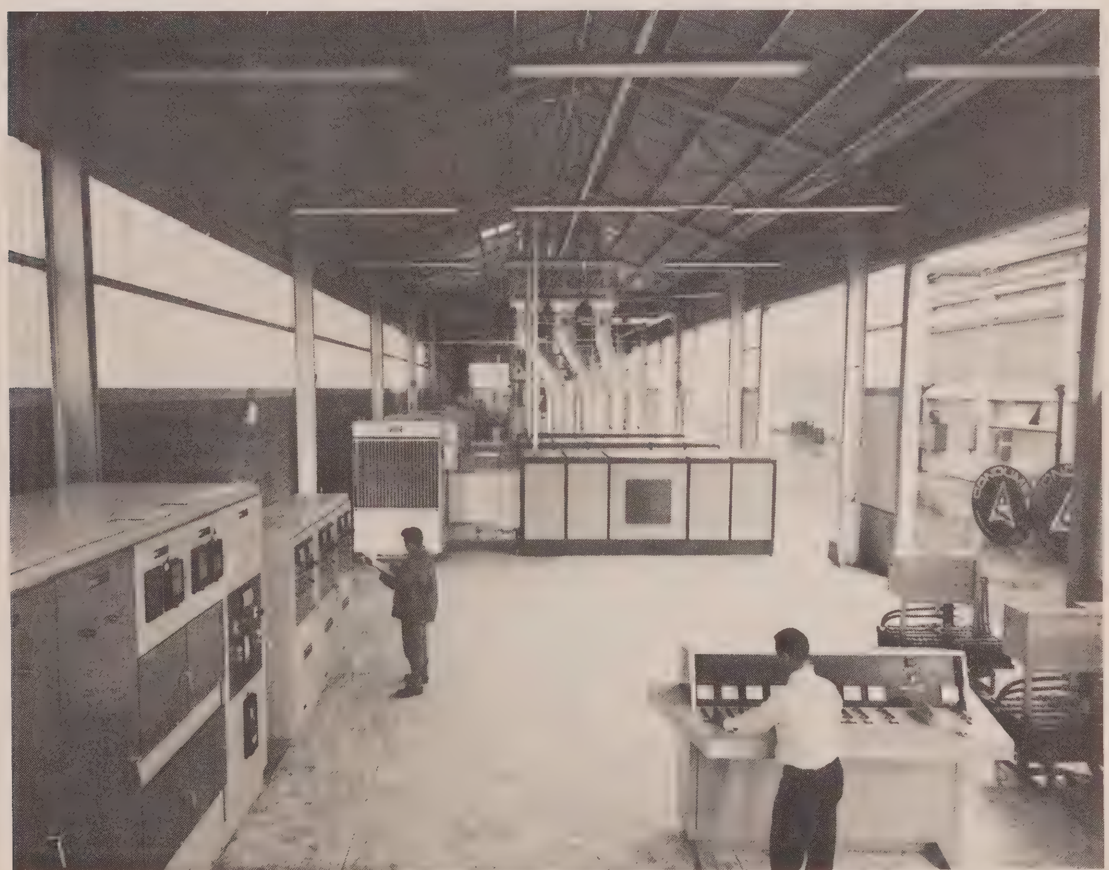
• Utility Composite Rate	2.5¢/kWh
• Fuel Cost	\$2.20/Btu x 10^6
• Tax Rate	47%

Since fuel and utility rates are expected to increase at a rate higher than inflation, an effort was made to obtain escalation rates with some credibility. These are as follows.

- The utility composite rate will increase 20%/year for the next 5 years and 8% from then on.
- The cost of fuel will increase 5%/year for the next 5 years and 8% from then on.

All of the above data were used to generate a Cash Flow Table that covered a 15 year span.

A table was generated for each of three assumed Installed Costs. \$400/kW, \$500/kW and \$600/kW (see at-



Solar gas turbines have found wide application in a variety of industrial plants. These three Saturn continuous duty generator sets supply continuous onsite power for all manufacturing operations at this modern cable plant in Mexico City. Exhaust from the turbines is ducted into a waste heat boiler and recovered to provide power for other plant operations.

tached). The Annual Cash Flow (ACF) was calculated from the following:

$$ACF = 8760\ AUF\ [UR - ((WN_f)\ (FC)\ /10^6 + MC)]\ (1 - TR) + IC/N\ (TR)$$

where

AUF = annual use factor - decimal

UR = utility composite rate - \$/kWh

WN_f = net fuel rate - B/kWh

FC = fuel cost - \$/mmB

MC = maintenance cost - \$/kWh

TR = tax rate - decimal

IC = installed cost - \$/kW

N = project life - years

The tabulation was calculated from the above data and the following assumptions:

WN_f = 4500/kWh

MC = \$0.0025/kWh

N = 15 years

Once the Cash Flow Table was calculated, the Internal Rate of Return was calculated by finding that value, i, which satisfies the following equation:

$$IC = \sum_{j=1}^{N} ACF_j/(1+i)^j$$

The results of the calculation are as follows:

Installed Cost	Rate of Return
\$400/kW	24%
\$500/kW	20.6%
\$600/kW	18%

Conclusion

Solar has used gas turbine engines to provide site-generated electric power in almost every conceivable application. There are certain industries, however, that present much more favorable economics than others.

In general, process industries are excellent candidates for cogeneration type systems because they have a high usage factor (three-shift operation), a high thermal requirement on a 24-hour a day basis, and they normally have a good understanding of the sophisticated

CASH FLOW TABLE

Year	Utility Rate UR (\$/kWh)	Fuel Cost FC (\$/mmB)	Installed Cost IC: \$600/kW — Annual Cash Flow ACF (\$/kW)	Installed Cost IC: \$500/kW — Annual Cash Flow ACF (\$/kW)	Installed Cost IC: \$400/kW — Annual Cash Flow ACF (\$/kW)
1	0.025	2.20	58.58	55.45	52.31
2	0.030	2.31	72.80	69.67	66.54
3	0.036	2.43	90.04	86.91	83.77
4	0.043	2.55	110.43	107.30	104.17
5	0.052	2.67	137.14	134.01	130.88
6	0.062	2.81	166.73	163.59	160.46
7	0.067	3.03	179.39	176.25	173.12
8	0.073	3.28	194.78	191.64	188.51
9	0.078	3.54	206.87	203.74	200.60
10	0.085	3.82	224.99	221.86	218.72
11	0.091	4.13	239.53	236.40	233.26
12	0.099	4.46	260.10	256.96	253.83
13	0.107	4.81	280.38	277.25	274.12
14	0.115	5.20	300.10	296.96	293.83
15	0.124	5.61	322.69	319.55	316.42

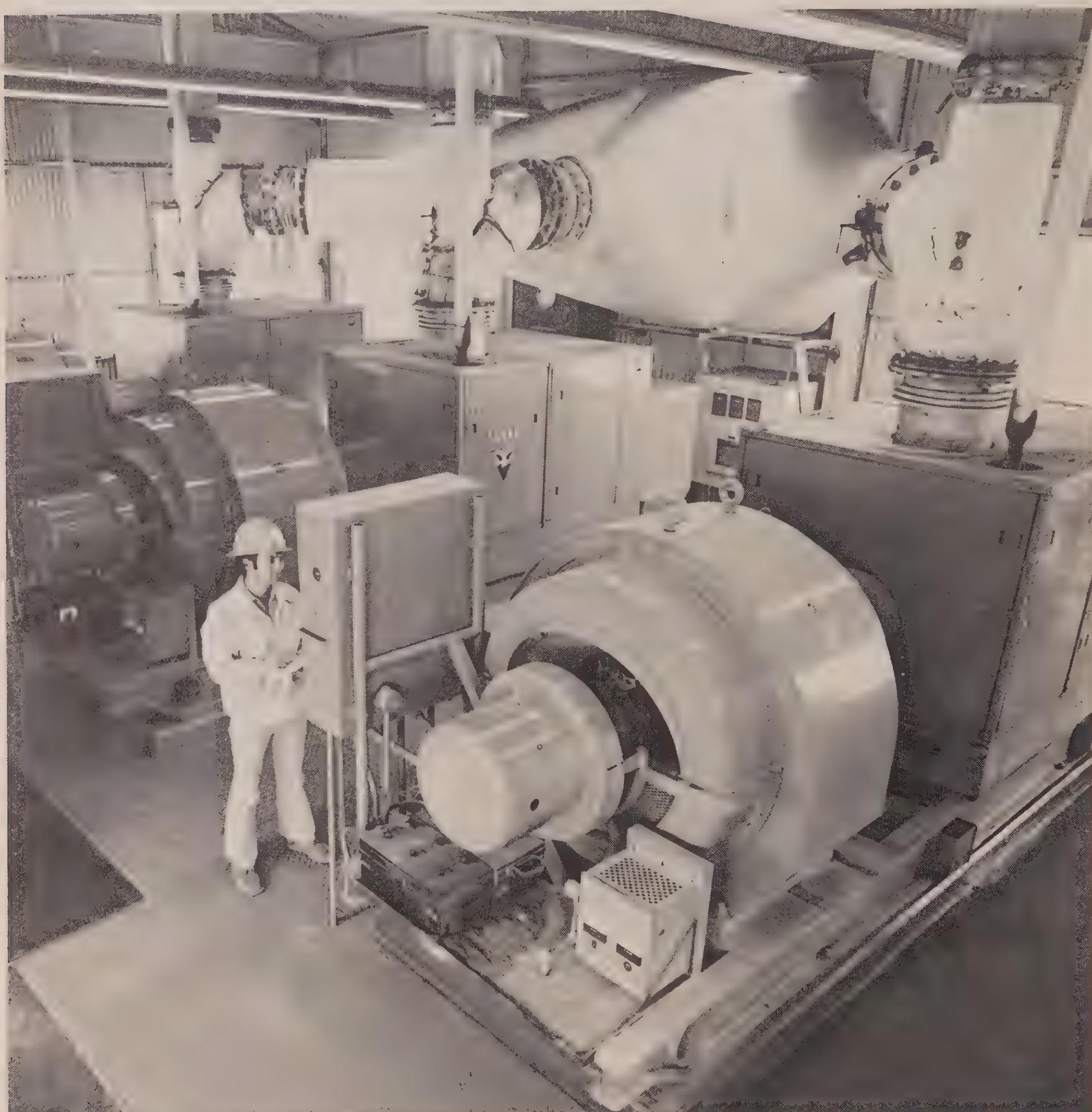
At this gas plant on the Gulf Coast near Cameron, Louisiana, seven 1200 horsepower Saturn turbine packages are employed in a variety of applications. Two 800 kW generator sets provide electrical power for the plant; two gas compressor sets are used in recycling operations and three mechanical drive packages drive propane refrigeration compressors. The exhaust of all seven turbines is ducted into a common manifold leading to a heat recovery unit for use in a lean oil heater.

Twelve Solar 800 kW Saturn gas turbine generator sets provide total power requirements for the USAF Satellite Tracking Station at Sunnyvale, California. Turbine exhaust is ducted into waste heat boilers to produce low pressure steam for air conditioning.

mechanical equipment described in this paper. These process industries include:

- Natural gas processing
- Petrochemical and refining
- Paper and pulp
- Food processing
- Textiles
- Clay, cement, and glass
- Lumber and wood products
- Metals

Solar's equipment can be used for either total or partial electrical power generation, refrigeration, and as direct drive for mechanical equipment in almost any of these applications.



Warren Petroleum Company installed three Saturn generator sets in 1961 at their facility in New Mexico. The units have been operating continuously since that time. Exhaust from the turbines is ducted into a heat recovery unit.

Discussion:

The Gas Turbine and It's Economics

MR. NEARY, *Solar Turbines Corporation*

Question: M. G. Bradwell, *B.C. Hydro*

I'm looking at this whole thing as an outsider, but since our speaker is from the West Coast, it may be a little south of us but maybe it's appropriate that I ask the question. A few moments ago you said that, taking into account the cheap rates for electricity in this area, (and I wasn't sure what you meant by that; whether you meant Ontario or were you in San Diego,) but you can answer that in a moment, that cogeneration just didn't exist as a possibility. My question is, in view of the factors you took into account, at what stage with increasing electricity rates, do you see a break-even occurring?

Answer: Mr. Neary

Firstly, to answer the first question, I meant in the Canada area here. I have been told that here there is normally an overall rate of about 1.6 cents per kilowatt hour. This number is similar to that that was used in the initial studies, which showed a 2% or 3% return on investment; something like that, very low, so anyway that was the number that was used there. Now the answer to the second question: -what we see is when you get up into about 2½, 2-3 times that number, somewhere around 3-4 cents per kilowatt hour, we see definite economic advantages to cogeneration in this size. With those kinds of electricity costs it will turn out to be 15% or 20%. Most of the studies have not been super detailed, though, where you take all the fluctuations into account.

Question: Stephen Detre, *Montreal Engineering*

On the second chart you showed of recoverable heat, there was a break in the recoverable heat at around 75 psi, and I was wondering what that meant.

Answer: Mr. Neary

that's the range when you are using exhaust heat recovery at 75 psi. That's where the economizer becomes marginal. You don't need that much feed water heating, and you can't do that much because you're going to drag your stack temperature down. It's not a firm line. It's to indicate that there is a region where the economizer is not going to be of interest any longer. It is not going to be economically feasible to put it on.

Question: Gaston Boucher, *Hydro Quebec*

I am somewhat amazed at the kind of heat rate you are getting out of your turbine, 4,500 BTU's for kWh. That means that if you inject 10,000 BTU's that you would get better than 70%. You would get 7,000 BTU's in electricity. How can you achieve such a highly efficient cycle?

Answer: Mr. Neary

That's an equivalent heat rate. It is not the simple-cycle heat rate. The simple cycle heat rate on the gas turbine as you well know would be up on the order of 12,000 or 13,000 or 14,000 BTU's per kWh. That number is the simple cycle heat rate adjusted for the heat which is recovered in the exhaust.

Question: C. R. Philcox, *Acres American Inc.*

I was interested in that gas turbine application for the pulp and paper industry. I understood you to say that the gas turbine was externally fired. Can you tell me whether the products of combustion go through the turbine, whether you see this as injurious, what the fuel is and whether its an indirect system or not.

Answer: Mr. Neary

I went over that very quickly, and it is externally fired and by that we mean just that this, instead of being a combustion chamber here, is a high temperature heat exchanger, which we're not running at too high a temperature by the way. It's a high temperature heat exhanger, the products of combustion do not go through the turbine. The turbine operates 100% on air. The air comes in here, goes through the cold side of the heat exchanger and then goes back into the turbine and then out. So, this is a heat exchange process with the products of combustion, and all of the associated problems of keeping the ash temperature in a proper location and so on an so forth. So, it is externally fired. There is a great deal of interest inside Solar Turbines in regard to that particular cycle. This, by the way, is designed to operate on wood, No 2, natural gas and No 6 and they can switch over. So, we're very interested in that particular cycle.

Into the high temperature heat exchanger, we have limited that temperature to 1,800°F, for the obvious reason that this is the first one. There are a lot of unknowns here. We know we can operate higher, but we're starting out conservatively.

Steam Turbine and Its Economics

J. B. McCULLUM
J. O. STEPHENS
Westinghouse Canada Limited

The presentation will discuss steam turbine characteristics, will tabulate budgetary costs for a wide range of sizes, and will give indications of costs associated with special features. Curves of the return on incremental investment will be shown and examples of various types of turbines will be given. Steam turbine "topping" results in the lowest rate per unit of generated power for incremental fuel requirements. The equivalent efficiency for the power generated can be as high as 78%. A further attractive feature of steam turbine topping is its suitability for power cogeneration using coal as fuel.

Steam Turbines

Their Cost and Application to IOSG

The industrialized nations of the world have reached their high standard of living through the use of electrical power. Electrical power has freed industry from its dependence on hydromechanical power, allowing factories to be located based on factors of production efficiency rather than proximity to rivers. The availability of electrical power has facilitated industrial expansion and has provided the flexibility required to manufacture today's products with their ever increasing complexity of systems both from a manufacturing and service standpoint.

In the evolution of electrical power and its distribution, large systems with complex interconnections have increased the efficiency of both generation and distribution sufficiently to maintain the low cost of such power. These electrical systems have thus been CHARTERED or FRANCHISED primarily towards the generation of electrical energy with, in some cases, by-product waste heat for local city heating. Within the confines of electrical power generation and distribution these systems have accomplished remarkable efficiency which has contributed immensely toward the development of our society.

Moving forward with technology to maintain our society requires an ever increasing use of energy with the moderate increase in population that is expected to continue in Canada. When the world demands for energy are considered along with the tremendous growth in population, conservation of world energy becomes more important. Canada is fortunate as being the only developed nation of the world to have sufficient hydro-carbon energy for its needs in the future. Even so, every effort must be made to conserve energy as international forces will demand goods and services from Canada that in themselves require energy to produce.

Cycle Definitions

(1) **The Steam Power Plant (Utility Type)**
Starting with the generation of power in a steam plant, Figure 1 shows a schematic diagram of the components often used in a utility system. Steam is raised in the boiler (or "steam generator") which is heated by burning fuel or by a nuclear reactor. The steam, under pressure in the order of 2,400 pounds per square inch, for a typical utility, flows to a steam turbine where its thermal energy is converted to mechanical energy. The mechanical energy is used to turn the shaft of the generator which produces electric power. The expended steam leaves the turbine and is condens-

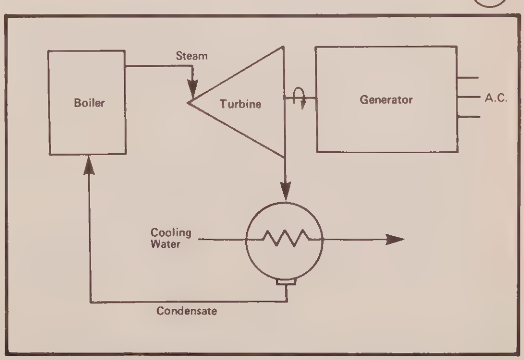


FIG. 1 - STEAM-ELECTRIC GENERATING PLANT SCHEMATIC DIAGRAM

ed back to water and returned to the boiler, completing the cycle. Externally-supplied cooling water removes the latent heat of vaporization, sometimes erroneously called "waste heat", an extremely important point to which we shall return later.

The temperature-entropy* diagram in Figure 2 is the map used by thermo-dynamicists to chart

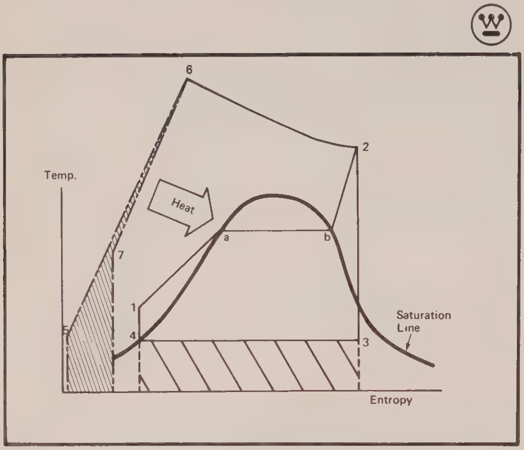


FIG. 2 - THE STEAM POWER CYCLE ON A THERMODYNAMIC PLANE

the course of steam through a power plant. Point 1 defines the state of the water entering the boiler. The path from Point 1 to Point 2 describes what happens as the water is heated and evaporated to steam. In this process from point a to b beneath the saturation line water at point a is changed to saturated (not superheated) steam at point b. This conversion takes place at constant temperature and is known as the "heat of vaporization." The location of points a and b depend upon the steam pressure. At the critical pressure of 3206 PSIA and above which is to the left of the saturation line water changes to steam as the temperature is increased without passing through the zone of vaporization. Some large utility steam plants operate above this critical pressure.

If we ignore for now the losses associated with the flow of steam through the pipe from the boiler to the turbine, Point 2 is also the state of the steam entering the turbine. The path from Point 2 to Point 3 describes the changes which the steam undergoes ideally as it passes through the turbine. At Point 3, all the thermal energy which can be used has been extracted from the steam which now is exhausted to the condenser. The temperature of the steam at Point 3 is quite close to the temperature of the plant's surroundings. However, the steam is still steam and for practical reasons must be condensed to water before it can be recycled. The condenser has thousands of tubes through which cooling water flows and removes the latent heat of vaporization from the steam causing it to condense. (The condenser can also be cooled by air directly instead of water, but this is an expensive method and is not often used.) The condensation process is "described" by the path in Figure 2 from Point 3 to Point 4. At Point 4 the condensate is pumped back to Point 1 to restart the cycle. It should be noted that the evaporation process (Point 1 to Point 2) is done under high pressure, usually thousands of pounds per square inch, whereas the condensation process (Point 3 to Point 4) is usually done in a vacuum. The difference in pressure causes the steam to flow through the turbine (Point 2 to Point 3). The thermal energy in the steam is converted to mechanical energy in the turbine. This energy is then used to spin the electric generator which is coupled to the turbine.

All thermal cycles have a boiler or steam generator that uses air as a heat transport fluid or one might say a working fluid. Thus, all thermal cycles are dual, using both air and steam. Figure 2 includes the air portion of the cycle in phantom. Ambient air is heated from Point 5 to Point 6 in the boiler furnace. This heat is then transferred to the water to raise steam in the boiler which cools the air and products of combustion from 6 to 7. At Point 7 the air and products of combustion are exhausted to atmosphere which cools to Point 5 to restart the cycle.

An important feature of Figure 2 is the hatched area under the line from Point 3 to Point 4, and Point 5 to Point 7. The amount of heat rejected from the power plant is proportional to these areas. The areas are not shown to scale. The area within Points 1, 2, 3, 4 and back to 1 represents the ideal useful work done by the steam. The efficiency of the cycle is given by the ratio of the work done (area 1, 2, 3, 4 to 1) to the total heat added to the cycle which is the sum of the heat to work (1, 2, 3, 4 to 1) plus the heat rejected represented by areas 3 to 4 and 5 to 7. There are tricks of the trade which can be applied to enhance the efficiency of this cycle (called the Rankine Cycle) but as a practical rule-of-thumb, its efficiency is about one-third. That is, of the energy supplied to the cycle, about one-third is converted to useful work and the remaining two-thirds is rejected. Notice the work "rejected" is used, not "wasted." This is an important distinction to which we shall return.

(2) The Process Steam Plant

Continuing on our way toward the industrial on site generation (IOSG) plant, Figure 3 is a schematic diagram of a typical industrial process steam plant. Again, steam is raised in the boiler

*Entropy is the relationship of change in internal energy with respect to temperature. Ideal compression or expansion of the working fluid (steam) is at constant entropy while addition (in boiler) or subtraction of heat (in condenser) from the fluid causes a change of entropy.

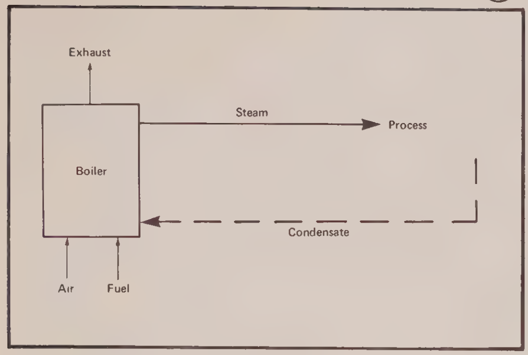


FIG. 3 - PROCESS STEAM SCHEMATIC DIAGRAM

and piped to where it is needed, say for heating spaces, drying product or process absorption. The condensate may or may not be returned to the boiler for recycling depending on the process. Hence the condensate return line is shown dotted. Some processes consume the steam, other contaminate the condensate so that it is unfit for recycling or it may be more economical to simply throw away the condensate and supply fresh make-up water to the boiler. The temperature at which steam is supplied to industrial processes is usually much lower than that supplied to electric power generating turbines.

In Figure 4, the thermodynamic "map" for process steam is plotted. Point 1' is the state of the

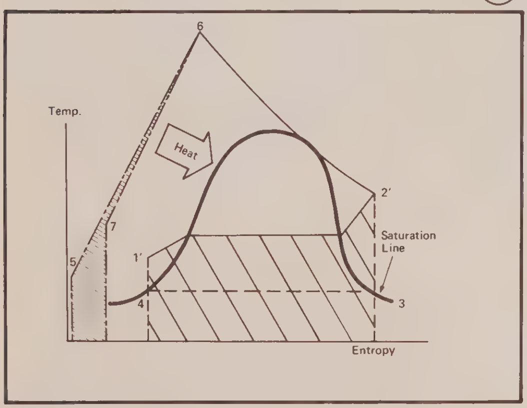


FIG. 4 - THE PROCESS STEAM "CYCLE" ON A THERMODYNAMIC PLANE

water entering the boiler. The steam raising process is depicted by the path from Point 1' to Point 2'. This time, however, there is no work process from Point 2' to Point 3 comparable to the power cycle. Hence this path is shown as a dotted line. Whether or not the condensate is recycled, however, the heat represented by the area under line 3, 4 and 5 to 7 is rejected just as in the power cycle. What's more, the area inside Points 1', 2', 3, and 4 does not represent work done in the strict sense, but does represent heat used in the industrial process. Again the heat represented by the area under lines 3 to 4 is to little value because the steam temperature is near the ambient air temperature and is difficult or expensive to upgrade it to useful heat. In addition the exhaust stack gases from 7 to 5 are usually lowered to a minimum of approximately 300°F which approaches the condensation temperature of S03. This combines with the water created by burning hydrogen in the fuel to form sulphuric acid. Since most boiler fuels will contain a trace of sulphur and of course, hydrogen, there will be sufficient sulphuric acid generation to cause corrosion of the final heat transfer protion of the boiler. Expensive stainless steels or other non-corrosive materials for the heat exchangers could be used to lower the 300°F temperature and make more effective use of this rejected heat but in most cases their use is not easily justified economically.

(3) **Industrial on Site Generation (IOSG)**

We now come to the point where we will assemble the Power and Process Steam Plants into one entity. There are numerous methods possible to accomplish this task. Only two will be illustrated and one or two others described to point the way.

Previous discussions have involved the high pressure, high temperature and condensing Utility plant of Figure 1 and 2. This is a large type of steam turbine generating set as illustrated in Figure 5 which is typical for a 250 MW Utility type unit. Even this is small by many utility standards. For the industrial on site generation (IOSG) smaller steam turbines are usually the practice to match the plant load. These smaller sized plants are usually more economical at lower steam conditions. Typically of these type of turbines if Figure 6 which is a 5000 KW size steam turbine with 600 PSIG inlet at 750°F steam temperature and 50 PSIG exhaust or "back" pressure. A larger size steam turbine similar to that furnished to a heavy oil extraction plant in Alberta is 15,000 KW at 900 PSIG at 925°F steam temperature and 55 PSIG exhaust pressure - Figure 7.

(4) **The Back-Pressure Method**

If one takes the power plant of FIGURE 1 and eliminates the condenser, sending the exhaust steam to process instead, an industrial on site generation plant is created. There is one small problem, however. The steam, as mentioned in the description of the power plant, is nearly at ambient temperature, so it may not be of much use to heat spaces or processes. A useful level of temperature can be provided by adjusting the turbine's exhaust steam pressure upward which also increases the temperature. This reduces,

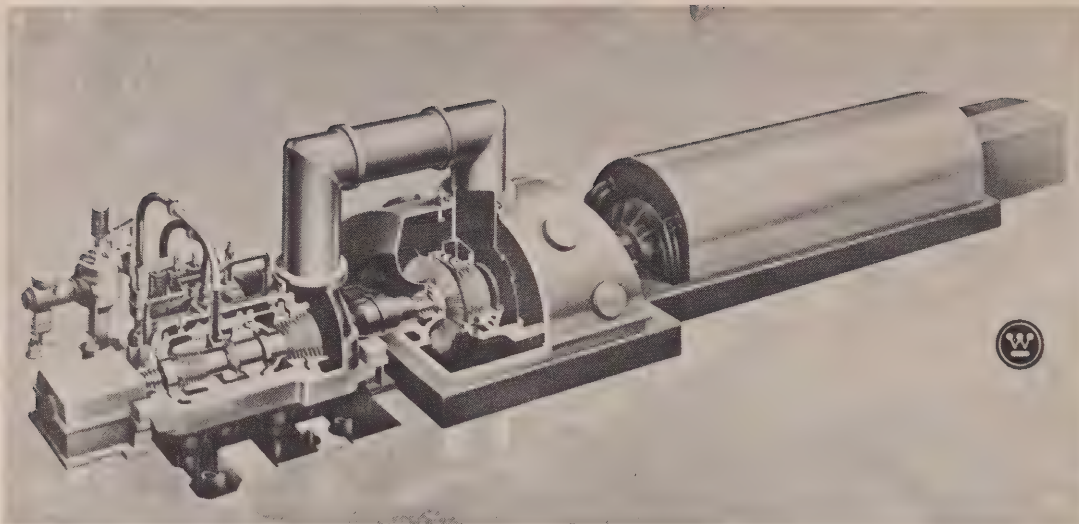


FIG. 5 - UTILITY TYPE STEAM TURBINE GENERATOR SET
250 MW 2000 PSI 1000^{o}F CONDENSING

FIG. 6 - INDUSTRIAL TYPE BACKPRESSURE 5000 KW STEAM TURBINE
600 PSI 750^{o}F 50 PSI BACKPRESSURE

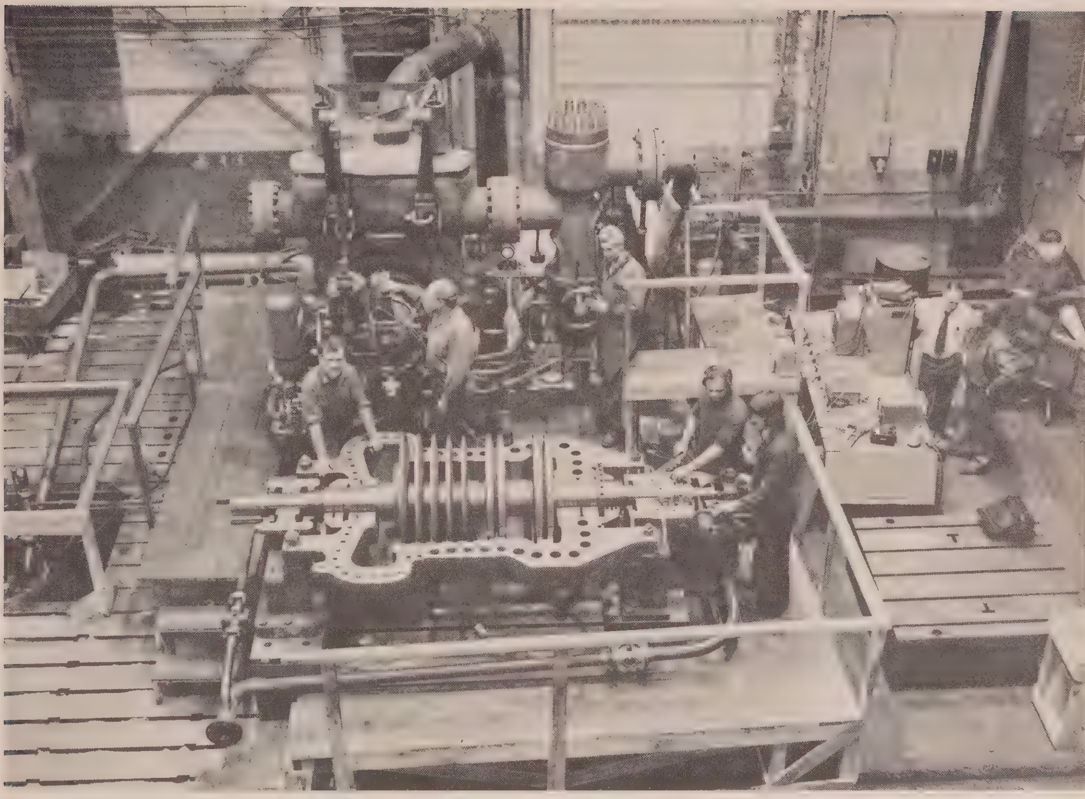


FIG. 7 - INDUSTRIAL TYPE BACKPRESSURE 15,000 KW STEAM TURBINE
900 PSI 925°F 55 PSI BACKPRESSURE

however, the quantity of power produced per unit of steam which passes through the turbine. This fact is reflected in the cost of power which we will deal with later on.

This kind of turbine is called a backpressure turbine, that is to say its exhaust pressure is above atmospheric air pressure (in absolute terms) and no condenser is used. This kind of turbine is also known as "non-condensing" because of the exhaust pressure or "topping," because of its position in the cycle. The steam sent to process may or may not return as condensate to the boiler for reasons discussed earlier. The condensate line is therefore dotted in Figure 8. Turbines can be designed for a wide range of exhaust pressures and can be tailored to meet specific process steam supply needs. This type of IOSG plant is the one most often evaluated. It is preferred because of its simplicity. Referring to Figure 3, imagine a backpressure turbine inserted in the steam line between the Boiler and the Process and you have the same arrangement as in Figure 8. There are many industrial steam installations similar to that shown in Figure 3 which would make it seem like a simple matter to convert all the nation's industrial steam-raising facilities to IOSG. But accomplishing this feat is actually

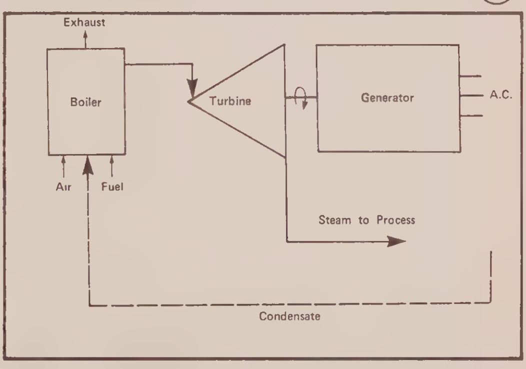


FIG. 8 - THE BACKPRESSURE IOSG UNIT SCHEMATIC DIAGRAM

more complex than a first look would indicate. As mentioned earlier, steam for power production is usually raised at higher pressures than steam for industrial purposes. Also, a glance at Figure 8, shows that the amounts of steam and electric power are fixed, i.e., if you want one, you have to take the other. On the other hand, if the turbine must be taken out of service, for instance, how is steam to be supplied to the process? Or, if the

process must be shut down what is to be done with the exhaust steam? The answers are not difficult technically, but they must be carefully evaluated economically. And that is one of the issues we will address in the discussion on pricing IOSG products.

(5) **The Condensing-Extraction Method**

Another way of creating an IOSG facility is shown in Figure 9. Here, we have taken the

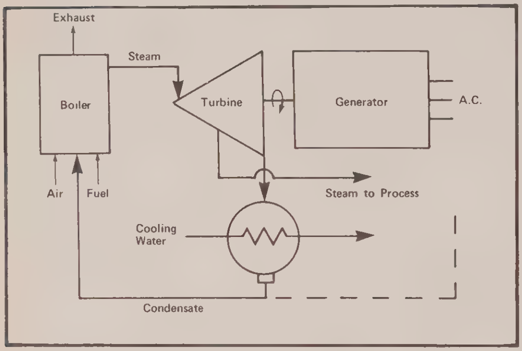


FIG. 9 - CONDENSING-EXTRACTION IOSG PLANT SCHEMATIC DIAGRAM

power plant of Figure 1 and added a steam line, called an extraction line, between the inlet and exhaust of the turbine. This is easily done in current technology - in fact, it is quite commonly done in utility power plants for the purpose of preheating the condensate before it returns to the boiler. (This is one of the techniques to which we alluded earlier, for improving the efficiency of power plants.) As in Figure 3, the condensate return line from the process is dotted as it may or may not be used for the process.

Steam may either be extracted from the turbine and sent to the industrial process or if not required sent to the condenser. Thus, the condensing - extraction type of steam turbine can provide an adjustment between extracted steam for process and electrical power generated. In general, slightly more than half of the energy of the steam is converted to work from the inlet of the steam turbine to a medium pressure extraction point. For instance if one pound of extraction steam is not required for process it will normally generate as much as 40 to 50% additional electrical (or mechanical) power in passing from the extraction point to the condenser. Such adjustments are accomplished while operating under load so that this type of steam turbine is very useful in industries that have a varying process heat demand. The quantitative effects will be demonstrated later.

(6) **Other Methods**

There are numerous other ways to combine electric power and steam production. The turbines represented in Figure 1 and 3 are "single-cylinder" machines. There are others which have two to four cylinders connected in series and/or series-parallel by steam lines, called "crossovers." A variant of the Figure 9 arrangement is to take the process steam from the crossover, see Figure 5, instead of in the middle of the turbine casing. Still another possibility exists when there are two turbine cylinders connected in parallel; one cylinder can be condensing while the other is non-condensing (backpressure). Be assured, however, that Figures 8 and 9 represent the fundamental IOSG plant arrangements and that all others are variants of these basic themes.

(7) **The Combined Cycle Plant**

So far, the conventional steam generating plant has been used to describe IOSG. It is also possible to use the combustion turbine in a IOSG facility. In fact several already exist, a large electrochemical facility in Texas being a case in point where 400 MW of Westinghouse combustion turbines supply combustion air for several million pounds of steam for electrical generation and for process. In this kind of IOSG facility, the hot exhaust gases from the combustion turbine (which drives an electric generator) are passed through a heat exchanger (called a Heat Recovery Steam Generator) in which steam is generated for either direct process use or first expanded through a backpressure steam turbine to generate additional electrical power and then to process. The superior efficiency of the Combined Cycle comes about from the fact that the air side of the boiler or steam generator is used to generate additional power. The combustion turbine compresses the air and burns all or a portion of the fuel in the turbine combustors. See Figure 10. Work is extracted from the air portion of the cycle bounded

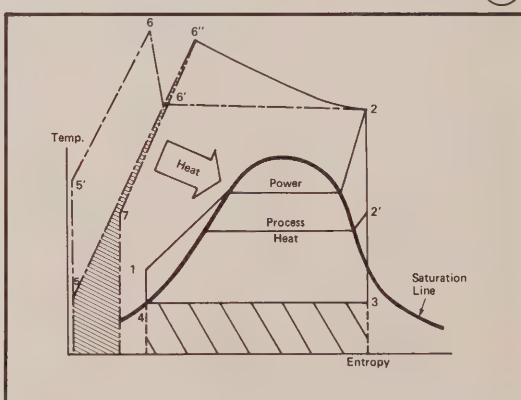


FIG. 10 - THE COMBINED GAS AND STEAM "CYCLES" ON A THERMODYNAMIC PLANE

by the area 5, 5', 6, 6' and back to 5. For a non-fired boiler, i.e. utilizes only heat from turbine exhaust gases, in a combined cycle there are addi-

tional losses on the air side from 7 to 5 as the combustion turbine must use additional air as a dilutent to hold the temperature within acceptable limits for the combustion turbine materials. This added loss is more than off-set by the work generated by the combustion turbine. Many plants, such as the previously mentioned electrochemical plant fire additional fuel in the gas turbine exhaust and raise the temperature to the boiler from Point 6' to Point 6" in Figure 10. This reduces the percentage exhaust stack losses and adds further to the efficiency of the cycle. It also provides a change in ratio of steam generation to electrical power.

As can be seen these cycles can become so complex that a detailed analysis for optimizing plant costs and efficiency becomes far too complex for a discussion such as this. However, confining analysis to primary variables i.e. fuel, electrical power and installed cost per KW, its possible to devise a first order "go" and "no go" measure to whether economics are attractive enough to warrant more detailed study. One factor that limits the gas turbine in IOSG use is the dependence on fuel type. Successful direct coal burning combustion turbines are not available so most installation must use gaseous or oil fuels.

In the case of blast furnace and coke oven gases from steel making the combined cycle normally has an added advantage. These rather low heating value gases contain dilutents that add to the exhaust stack losses in a steam boiler and thus reduce the steam cycle efficiency. For the combined cycle relatively large quantities of excess air are required for the combustion turbine as explained above so that the gas turbine cycle efficiency is not so affected. Only when the waste heat boiler is heavily fired almost to stoichiometric mixture of air and fuel does the combined cycle become similarly affected.

In order to avoid introducing too many aspects of IOSG, which may tend to confuse this presentation, we will return to the use of the steam plant for further discussion.

The IOSG Advantage

We are now ready to discuss the thermodynamic advantage of IOSG plants using the large utility type of steam turbine as an example. Superimposed in Figure 11 are the thermodynamic plots of the power generation and process steam cycles of Figures 2 and 4. In the descriptions for each of these latter figures, we pointed out that the area under line 3, 4 and 5, 7 (same as in Figure 11) are proportional to the amount of heat which must be rejected to the environment because it cannot be used. (Another way to state this is to say its thermodynamic availability is nil). But notice that there is only one such area (3 to 4) for the steam cycle in Figure 11, whereas we had two in Figures 2 (a to b) and 4 (c to d) taken together. Herein lies the advantage of IOSG. By combining the power production and process heat functions into one plant, the total amount of rejected heat is reduced, the precise amount being dependent on the particular application. In other words, we can do two jobs, i.e. power generation and process heating, with the steam before discarding or recycling it. By way of illustration, consider the following. Figure 12 is

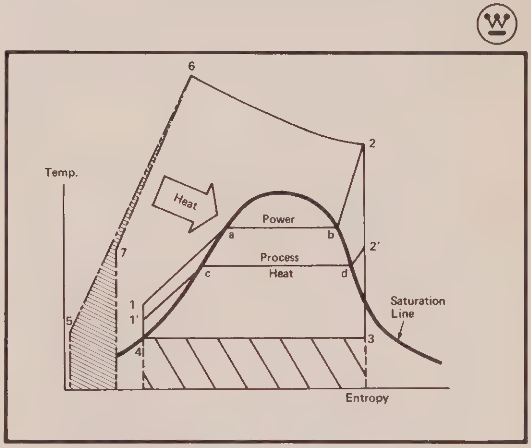


FIG. 11 - THE IOSG PROCESS ON A THERMOCOUPLE PLANE

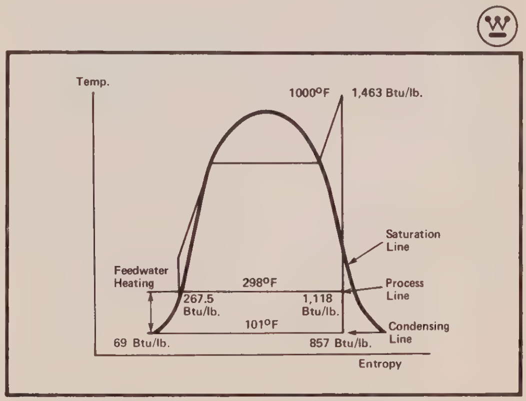


FIG. 12 - TYPICAL IOSG CYCLE -- 50 PSIG PROCESS STEAM

a repeat of only the steam portion of Figure 2 with additional information about the steam power plant cycle. The numbers on the chart are values of unit energy content in the steam at the salient points in the cycle. These are ideal values shown for a cycle whose upper pressure is 2400 psi absolute and whose maximum temperature is 1000°F. The lowest temperature of the cycle is 101°F representing good utility steam station design practice.

The amount of energy added to the steam is given by:

Energy Added = 1463 - 69 = 1394 BTU/lb

The amount of energy which is ideally converted to electricity is found by:

Work = 1463 - 857 = 606 BTU/lb or 0.178 KWH/lb of steam passed

The amount of energy rejected to the environment is given by:

Reject Energy = 857 - 69 = 788 BTU/lb

the efficiency of this cycle is simply the ratio of the useful work derived, 606 BTU/lb, divided by the energy added, 1394 BTU/lb, or 43.5%. (The real efficiency of such a cycle is lower due to the added heat rejected by the exhaust gases from the boiler).

An ideal IOSG cycle is shown in Figure 13, a repeat of the steam only portion of Figure 11 with values of

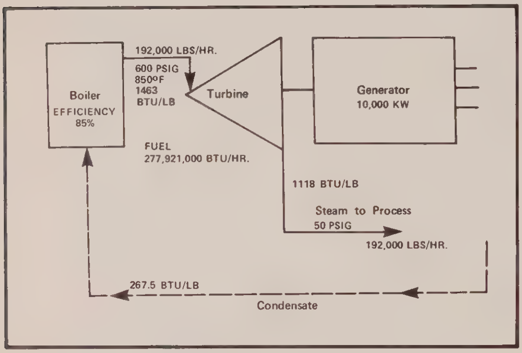


FIG. 13 - THE BACKPRESSURE IOSG UNIT FOR 10,000 KW AND 50 PSIG STEAM TO PROCESS SCHEMATIC DIAGRAM

enthalpy (heat of the steam) added at the more important points of the cycle. The air side of the cycle will remain the same in both cases so for simplification of comparison it is not shown. Process steam need at 50 PSIG or 64.7 PSIA, about 298°F, is assumed. Since the expansion of steam through the turbine is terminated at a higher pressure in this case than in the power-only case of Figure 12, the unit amount of work derived from the cycle is proportionately reduced:

Work = 1463 - 1118 = 345 BTU/lb or 0.101 KWH/lb of steam passing through the ideal turbine

The amount of energy added to the steam is also reduced:

Energy Added = 1463 - 267.5 = 1195.5 BTU/lb

The amount of energy passed on via the exhaust steam to the consuming process is:

Process Energy = 1112 - 267.5 = 844.5 BTU/lb

Since the power portion of the steam cycle rejects no energy to the environment (all exhaust energy goes to process), the power portion has a theoretical efficiency of 100%. In other words, all the energy added to the steam to generate power does indeed end up as turbine work in the ideal cycle. The remaining energy that was added to the steam in the boiler goes to process and the exhaust stack. Note however, that this particular IOSG cycle generates only 57% (.101 KWH ÷ .178 KWH) as much electricity per pound of steam used as does the power-only cycle. To generate a given amount of electricity, the amount of steam passed through the turbine in the IOSG case must be increased some 75% (606 ÷ 345 = 1.75) over the amount in the utility power only case. It has been implicitly assumed in using the steam that all the condensate from the process is returned to the boiler at 298°F (equivalent to 50 PSIG steam). Should the process be incapable of using all the steam produced or should the process be of such a nature that only a part or none of the condensate at 298°F can be returned to the boiler, the energy balance would be upset and the advantage of IOSG is reduced.

The above provides a description of the various cycles that usually occur in an industrial application. Many variations of these cycles are used depending upon the type of industry and its steam and electrical requirements.

Heat Rejection

Returning to Figure 8 displaying a schematic arrangement of a backpressure steam turbines the industrial process can be termed as a heat "sink" and eliminates environment effects of this heat rejection. The importance of this fact is better understood when it is realized that to condense one pound of steam of 1000 BTU/lb in a condensing steam power plant, .8 of a pound of cooling water must be evaporated. This is the approximate case whether a cooling tower, pond, lake, or river is used for cooling water. Since the earth is a very good insulator most of the energy must be rejected to the atmosphere in the form of vapor. Thus, for an industrial plant generating 10,000 KW of electrical power and exhausting to process 50 PSIG steam, 192,000 lbs per hour of steam would be used. For the utility with its condensing cycle to supply the 10,000 KW as purchased power to the industrial, with its higher steam condition and a condensing type of steam turbine, approximately 70,000 lbs/Hr. of high pressure steam flowing to a high vacuum condenser would create an additional 56,000 lbs per hour or 161, 280 US gallons per day of water vapor. The IOSG plant by generating the 10,000 KW in a backpressure steam turbine will save the utility the problem of disposing of 161,280 gallons per day of vapor plume. This is an advantage of IOSG that is sometimes not realized.

Economics

By relating some of the variables that are high in cause-to-effect on the ultimate evaluation, it is possible to assist in making rapid evaluations of many schemes so as to narrow the number of arrangements or schemes that produce the highest return on investment. Normally installed cost of added equipment, maintanance, added manpower, if any, taxes and capitalization are almost always peculiar to the specific application. The relationship of fuel costs, electrical power costs, and added investment cost in $/KW develop a common relationship and can be plotted in a single graph.

To simplify the evaluation process, however, industrial applications have been compared in cost of fuel and electrical power using the following schemes:

1. Purchase power with separate steam generation -Figure 3.
   a) cost of electrical power.
   b) cost of fuel to generate 50 PSIG for process

2. Self Generation IOSG - Figure 8.
   a) cost of fuel for high pressure steam for 5,000 KW 10,000 KW, 15,000 KW and 20,000 KW with 50 PSIG backpressure.

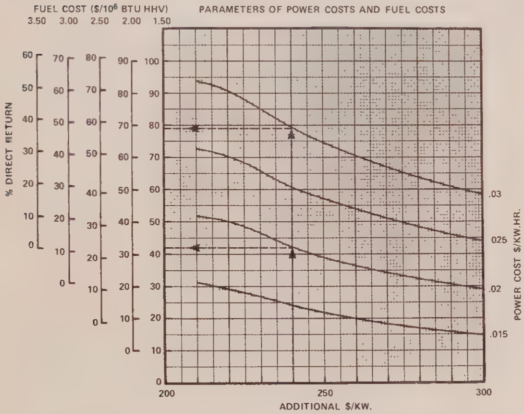
Only the backpressure turbines have been considered so that a direct comparison of the two types of operating can be more visible. The amount of steam required by the industrials has been assumed to be that required to generate the various powers shown in paragraph 2 above.

In preparing this curve the amount of fuel for the "purchased power with separate steam generation" has been subtracted from the fuel for the IOSG self generation scheme thereby reflecting the high efficiency of power generation in the IOSG plant.

By using this cycle for the various sizes; it is possible to develop the curve so that a quick measurement of whether the savings of IOSG will have sufficient return on investment to be considered further. In preparing curve #14, the following variables have been included.

FIG 14

ANNUAL RETURN ON INCREMENTAL INVESTMENT IN PERCENT
VS.
INCREMENTAL $/KW. INSTALLED
WITH
PARAMETERS OF POWER COSTS AND FUEL COSTS



Fuel Cost $/Million BTU $1.50 $2.00 $2.50 $3.00 $3.50

Added investment cost $/KW 200 250 300

Electrical power costs mills/KW HR 15 20 25 and 30

Size KW	5,000	10,000	15,000	20,000
Steam Cond. (Normally used by an Industrial)				
Press #/in.^{2}	400	600	850	850
Temp. °F	750	850	900	900
Back Press. PSIG	50	50	50	50
Feed water temp. °F.	225	225	225	225

For an example of calculations see Appendix I.

Using the data in Appendix I for a 10,000 KW installation at 240/KW added investment, 20 mill electrical power costs, and $1.50 per million BTU fuel cost the % return on direct investment is 42%. At 30 mill power cost the % return is 79%.

The cost of electrical power and the cost of fuel can usually be obtained once the amount of electrical energy and process steam are known. An estimate of installed cost of equipment in $/KW net generation can be a lengthly and costly study when twenty or thirty various schemes are involved. In order to make effective use of Curve #14 to eliminate the lesser candidates it is possible to use the FOB price of the steam turbine generating set and apply multipliers for the installed cost of a complete plant, Figure 15. These multipliers

MULTIPLIERS FOR BACKPRESSURE STEAM TURBINE

GENERATOR SETS VS SIZE

FOR

INDUSTRIAL ON-SITE GENERATION PLANTS

MULTIPLIER X FOB PRICE = APPROXIMATE INSTALLED COSTS

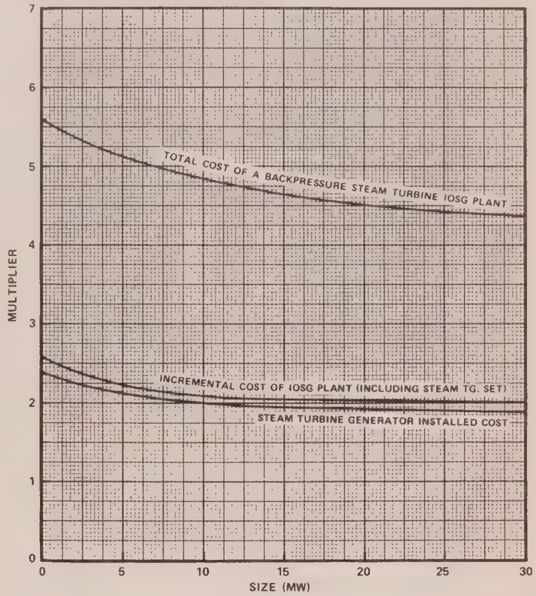


FIG. 15

have been developed from numerous studies as listed in the acknowledgements plus experience in installing steam turbines in industrial applications. At best they are approximate and are only to be used as an expedient measure of various schemes. The estimating prices of backpressure steam turbines are tabulated in Table 1.

In determining the approximate installed plant cost it is assumed that the study is for a new installation where the decision is to purchase power and install a boiler for low pressure process steam generation versus an increment to this investment for industrial on site generation of power using a backpressure steam turbine and a larger boiler.

For purchasing power there will be a cost associated with delivering of the power to the industrial site plus lowering the voltage to that required for the industrial distribution system. Even with on site generation it

TABLE 1

STEAM TURBINE ESTIMATING CHART

- For Typical Conditions -

SIZE (KW)	INLET MAXIMUM PRESSURE	INLET MAXIMUM TEMP.	EXHAUST	TOTAL $	$ PER KW	APPROX. EFFICIENCY	FRAME W	TYPICAL DELIVERY	NOTES
500	300	550	25	63K	120	60	CE125	9 mo	1,2
1,000	850	900	200	125K	125	70	EH125	9 mo	1,2
2,000	600	750	175	250K	125	72	EH125	9 mo	1,2
4,000	600	750	50-100	600K	150	73	EM25	14 mo	1,2,5*
5,000	850	825	50-300	750K	150	75	M25	14 mo	1,2,5*
7,500	850	850	50-150	940K	125	76	M25	15 mo	1,3,5
10,000	850	850	75	1.15M	115	76	M32	15 mo	3,5
12,500	850	850	75	1.4M	115	77	M32	15 mo	3,5
15,000	850	850	75	1.60M	110	78	D	16 mo	3,5
20,000	850	850	75	2.1M	105	78	D	17 mo	3,4,5
25,000	1250	900	75	2.5M	100	79	D	18 mo	3,4,5
30,000	1250	900	75	3.0M	100	80	D	20 mo	3,4,5

NOTES:
1. Baseplate mounting to simplify installation.
2. Exhaust pressure control.
3. Extraction and/or exhaust pressure control.
4. Double extraction available with condensing exhaust.
5. Uncontrolled extractions available to improve plant efficiency.

* Technically feasible but seldom economically justifiable.

may be more economical to generate at a higher voltage and transfer to a lower voltage for plant distribution. In any event there is a cost associated with both systems to deliver power to the industrial grid system. This will be called "power conditioning."

A typical system for a 10,000 KW backpressure (50 PSIG) on site generation plant would appear as follows:

IOSG Detailed Analysis of Investment Comparison in $1,000 Steam Generation at 50 PSIG for Process

FUEL OIL FIRED

	Purchasing Power Plus L.P. Steam Boiler	On Site Generation 10,000 KW	Incremental Added Investment
Boiler (Steam Gen.) Plus all auxiliaries and water treatment	L.P. Steam *3,147	L.P. Steam *3,274	127
Steam turbine generator installed	-	2,311	2,311
Power conditioning (transformer & distr.)	256	218	(38)
	$3,403	$5,793	$2,400

*These are field erected boilers. For steam requirements of 200,000 lbs per hour or less packaged boilers may reduce the installed cost by as much as 25%.

With a new installation, one or the other systems, i.e. purchased power or self generation, must be used to supply the new industrial or the new addition to an existing plant. In such a case the decision to purchase power or generate power on site is based upon the added cost of the generation equipment, and its additional steam requirements plus the power conditioning. In this case the $2,400,000 is the added incremental investment required for 10,000 KW of on site generation or $240/KW.

An expeditious way of determining this would be to use Curve #15 for the multiplier and Table I for estimating FOB prices. For an incremental cost at 10,000 KW the multiplier is 2.09. The 2.09 x 1,150,000 cost of 10,000 KW steam turbine from Table I = 2,400,000 or $240/KW. Thus, Figure 15 multiplier times the FOB estimating price will approximate a new IOSG backpressure steam turbine generating plant.

In preparation of Figure 14 for return on incremental investment the following incremental installed costs have been used for the various size of industrial on site generation (IOSG) plants.

	5,000 KW	10,000 KW	15,000 KW	20,000 KW
Incremental Costs $/KW	300	240	220	210

Where preliminary information indicates significant deviations from these installed costs, Curve #14 will deviate slightly.

The use of Curve, Figure 14 will provide the gross return on investment for screening the various schemes for a proposed IOSG installation. Once the last schemes have been selected a detailed annual operating cost summary should be prepared as shown in Appendix I using present day fuel and power costs as well as the expected adjustments to these costs over the life of the plant. As shown in the latter example of Appendix I the costs of owning the equipment, water treating, operating, and maintenance, should be added to the analysis. Adjustments should also be made by the proposed owner depending upon his accounting procedures.

As shown by the tabulation in Appendix I a retrofit to an existing plant is not as favourable as a new installation since only the book value of existing equipment can be deducted from the proposed IOSG installation.

These costs in $/KW may seem low to a utility but it should be remembered that the steam turbine is a backpressure type without the expensive low pressure section and there is no condenser and no circulating water system requirement.

For a coal fired ISOG plant the cost of the steam generation equipment will increase plus the added facilities for coal handling. Typically the above tabulation will be as follows.

IOSG Detailed Analysis of Investment Comparison in $1,000 Steam Generation of 50 PSIG process steam. COAL FIRED

	Purchased Power Plus Low Pressure Steam Boiler	On Site Generation 10,000 KW	Incremental Added Investment
Boiler (Steam Gen.) Plus all Auxiliaries and Water Treatment	$5,500	$ 9,727	$4,227
Steam Turbine Generator Installed Complete		2,311	2,311
Power Conditioning (Transformer & Distribution)	256	218	(38)
	$5,736	$12,478	$6,722

The coal fired IOSG plant will be considerably more expensive due to the field erected type of boiler and the coal handling equipment. This added cost of equipment for firing coal requires a sizable reduction in cost of coal per million BTU as compared to fuel oil to make this fuel economically attractive. This fact is usually recognized in market pricing of coal. It is suggested that the numerous schemes of steam supply for the industrial user be first analysed using oil fuel to reduce the number of viable schemes. Then if the price of coal is appreciably less than oil, make a detailed annual operating cost analysis as shown in Appendix I.

Spare Capacity

The amount of spare capacity for an IOSG plant will depend upon the industry involved, its location, its type of product etc. Each case of the remaining schemes must be reviewed in detail to obtain a vaiable solution. Between the industry and the utility there is a possibility of an equitable solution which can result in economy of both parties and at the same time conserve energy.

Business Environment

The industrial plant will usually require one half to one dollar investment for each dollar of gross revenue, while the regulated utility will require as much as four dollars investment to generate one dollar of gross revenue. Thus, the two types of businesses have different return on investment requirements and equipment amortization times. The tax structure can also be different which may further add to the differences in the two types of businesses.

In general the industrial would much prefer to invest in manufacturing plant to increase production rather than invest in a power generation system that does not necessarily add to his product income.

One possible solution that uses the most favorable characteristics of each type of business and at the same time conserves energy, is for the utility to own and operate the IOSG plant. Then the utility can sell both electrical power and steam (or waste heat) to the industrial and in many cases obtain fuel from the industrial in the form of oil (refinery) low B.T.U. gas (steel mill), waste wood (paper making) etc. This reduces the spare capacity and may lower the required return on investment. Such an arrangement including the above factors has the following advantages:

1. Spare capacity reduced.
2. Usually lower required return on investment.
3. More reliable electrical power since the system is less dependent on transmission to the IOSG plant.
4. Conserves energy (70 to 80% incremental efficiency vs utility all generating plant of 40%).
5. Does not add to environmental pollution (water vapor) for the IOSG increment of power.
6. The industrial plant can concentrate on investment in product rather than power generation.

The major disadvantage to the utility for such an IOSG plant is the increased operating and maintenance of numerous small plants. Since the regulated utility rate structure is based upon investment and since the IOSG could be a reduction in investment per KW, the utility owned IOSG is less at-

tractive to the utility. Also, the added operating and maintenance of numerous plants detracts from the operating income. To offset this disadvantage the gains by the IOSG need to be shared between the industrial and the utility.

Conclusion

For an IOSG evaluation it is possible to use Curve #14 to quickly determine the best candidate of several schemes. For this evaluation, however, there are several items that should be determined before detailed effort is expended.

1. Cost of electrical power in $/KW HR including the demand charge during inspection periods of the generating equipment. A convenient method is to convert the demand or stand-by charge to $/KW Hr and add it to the cost of power per KW HR.
2. Cost of fuel in $/million BTU of higher heating value, which has been used in this Analysis.
   Note: Many North American boiler efficiencies will be based on higher heating value while European boilers, combustion turbines, and diesel and gas engines will be quoted on lower heating value. See Appendix II for explanation.

With these variables established, an estimate of the added installed cost of equipment using Table I and Curves #14 and 15 will permit a rapid determination of which schemes should be studies in more detail as outlined in Appendix I.

Acknowledgements

(1) Cycle Diagrams extracted from the paper titled "What is the True Cost of Electric Power from a Cogeneration Plant" by Wilfred H. Comtois, presented at the 40th American Power Conference -Chicago, Illinois, April 24-26, 1978.

(2) Cost Data based upon an internal Westinghouse Electric study by P. F. Schweizer and R. E. Sieck. This study used data from:

(a) Resource Planning Assoc., Inc., "the Potential for Cogeneration in the Chemical Industry by 1985", RA-77-1018, June 17, 1977.

(b) Thermo Electron Corp., "A Study of Inplant Electric Power Generation in the Chemical, Petroleum, Refining and Paper and Pulp Industries", TE 5429-97-76, 1976.

(c) M. C. Doherty, "Selection of Boiler Steam Conditions for Industrial Power Plants", ASME 75-IPWR-12, May, 1975.

(d) M. C. Doherty, "Investment Economics of Industrial Gas Turbines", ASME 77-GT-26, March, 1977.

Discussion:

The Steam Turbine and Its Economics

J. B. McCULLUM, *Westinghouse Canada Ltd.*

Question: Gerry Lewarne, *Morris, Wayman Ltd.*

Mr. McCullum, on the previous diagram that you had on the slide in which you had the three cost curves kWh installed, the top curve you had referred to the kW installation charge made to electricity generation if there was no market for your exhaust steam. Is that correct?

Answer: Mr. McCullum

No, the top curve of those three curves was a curve of multiplier versus size of unit, and it takes into account the total cost of the complete steam generation facility to serve the steam flow which is all going through the turbine. (I use the term "Steam Variation" to mean boiler). You had a second part to your question. Was there any of the electrical capacity being sold to someone else? The answer to that is we didn't consciously think of that. We just assumed that it was displacing electricity that was costing something in the range of 15-30 mills, (or 10-30 mills.)

Question: Mr. Lewarne

And your lower curves were the incremental cost of installing the turbine where high pressure steam was available?

Answer: Mr. McCullum

No. If you're going to build a plant, and you say I have to have a steam production facility to deliver 192,000 lbs/h on that diagram, and how much more would it cost me to have a steam turbine generator set on that plant? There is an influence of that on the boiler itself, because the steam is a little different quality. So there were two lines at the bottom, close together and one at the top. Two lines at the bottom, the lower one was just the steam turbine generator set and all the hardware all the manufacturers like to sell, and then the line just above that is the increment in the cost of the steam production facility, or the boiler, to provide the difference in quality in the steam.

Question: Derwin Hughes, *Shell Canada Ltd.*

The last two presentations emphasized the importance of knowing future electrical costs and working out the feasibility of these co-generation projects. I would like to request that before we leave today, perhaps someone for Hydro could give us the latest forecast, for the next 10 years say.

Question: J. O. Stephens, *Westinghouse Canada Ltd.*

One thing that was mentioned and passed over a little bit earlier yesterday was the heat sink that the industrial creates. When I start analyzing that a bit,

it order to condense a pound of steam, you have to evaporate about 8/10 of a pound of water. Now, this gets evaporated, and it doesn't make any difference whether you dump it into Lake Ontario or any other place, that water evaporates because the earth is a real good insulator. So, to get rid of your heat, you must evaporate some water. The cloud over Hamilton is a pretty good indicator that this happens, because they have millions of gallons of water they put into the atmosphere. Now for say a million kW, as was mentioned yesterday, you might be evaporating in the neighborhood of 12-15 million gallons of water/day in a thermal plant for the utility to generate that power. That's kind of lost here because Lake Ontario is so large and the sun and energy on that is such a small percentage, but when you concentrate this into an area, you begin to shift the weather pattern a little bit, so that problem is taken away from the utility when you go to co-generation. This is one other advantage in this whole process. For nuclear generation, it may be 20 million gallons a day for 1 million kW.

One other comment was in the combustion turbine (I'm in the hot air business.) The low BTU gas around many industries - we shouldn't throw out the combustion turbines, saying that coal is the future, therefore lets not put any emphasis on it, because you can get some real savings, particularly in the low BTU gas areas such as blast furnace gas where your boiler efficiency will decrease 10%-15% just due to the added dilutents going into the atmosphere, whereas, the combustion turbine has to pump extra air to get the dilutents to cool the products combustion so it can pass through the turbine. So this aspect of the combined cycle burning blast furnace gas has another 15% advantage over the normal steam turbine generating sets. So, it is a useful tool and can add extra kW for a given amount of fuel.

Question: Mike Park, *Falconbridge Nickel Mines Ltd.*
This is not really a question but a general request for information. Sometime during the last year I recollect seeing a very short news release that some company in Japan had succeeded in using a refrigerent type of material, freon or some such material, for low energy heat recovery and using this to drive a turbine of some description. Does anybody know anything about this type of thing? If so, what are the possibilities for it?

Answer: Mr. McCullum
I have heard just a little bit about this. It might not be exactly the same thing you're talking about, but there is an outfit in Albany, New York which is called MTI (Mechanical Technology Incorporated) that has been doing work on cycles of the kind you are describing, and that is about all I can tell you. You might contact them to find out more about it. I don't remember anything about Japan though.

Answer: R. S. Broadfoot, *Lummus Co. of Canada*
We have been doing studies for particular gas transmission companies on the recovery of gas turbine heat using those low temperature cycles.

The Importance of Steam Balance for Economic Operation of Cogeneration

J. R. PARROTT,
The Great Lakes Paper Co. Ltd.

By-product power can be generated in most process industries and can reduce the cost of power substantially. However, with the escalation of fuel and purchased power costs, the economics of cogeneration have again come under review. This paper begins with a feasibility study done prior to a recent steam turbine installation at The Great Lakes Paper Company, and looks at the effect of the turbine generator on the costs of cogeneration due to changes in: steam balance, fuel costs, purchased power costs, steam conditions, load factor, etc.

Introduction

The Great Lakes Paper Company has its manufacturing facilities located in a single large complex within the City of Thunder Bay, Ontario. The producing units include:

Newsprint Mill	- 415,000 tons per year
Kraft Mill	- 450,000 tons per year
Stud Lumber	- 100 million board feet per year
Waferboard	- 240 tons per day

The electric power required for these operations during 1977 was one billion kilowatt hours. Approximately 50% of this can be generated in steam turbine generators. The steam is generated in two steam plants which are interconnected by a high pressure steam line one half mile in length. The combined capacity of the plants is 2.2 million pounds of steam per hour at 850 pounds pressure and 900°F temperature.

There are five turbine generators installed. Three are located in the Newsmill Steam Plant and consist of:

General Electric	- 4,000 KW-installed 1927
General Electric	5,000 KW-installed 1927
Siemens	- 17,100 KW-installed 1962

The General Electric Turbines are operating at 450 pounds pressure and 650°F.

Two turbines are installed in the Kraft area:

Stal Laval	- 22,800 KW - installed 1974
Stal Lavel	- 34,800 KW - installed 1976

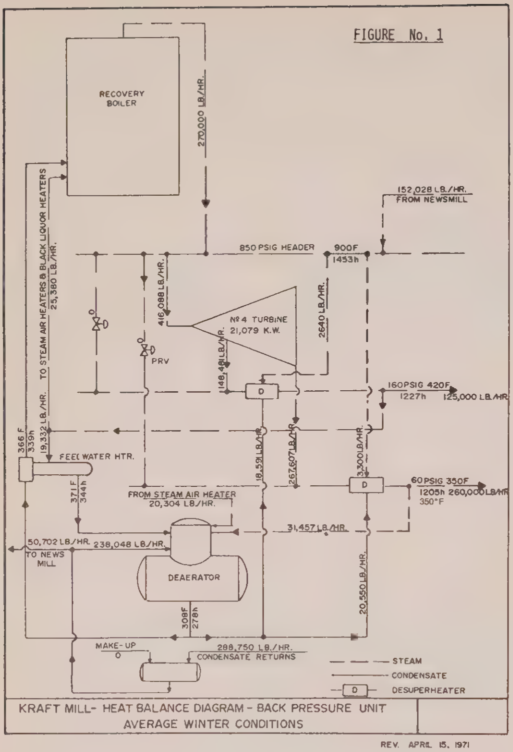
giving a total installed capacity of 86,700 KW. At the present time the installed capacity exceeds the steam demand to process, therefore some units are operating below their capacity.

In preparing this paper, we were asked to deal with the economics of on-site power generation as it is affected by the steam balance for the process. In the recent 1974 installation of our No. 4 Turbine extensive study of steam systems was undertaken by our consultants, W. P. London and Associates, and I have drawn from this study. I will confine myself to this one Turbine application, since I believe most of our lessons learned will be evident and it will not be necessary to take in the broad scope of the whole plant.[1]

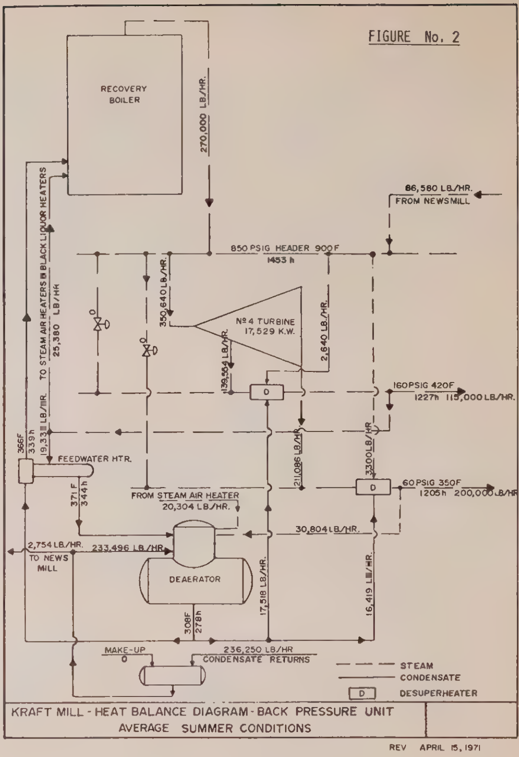
Fig. 1 - Illustrates the steam flows to process as they existed prior to the installation of No. 4 Turbine. The Kraft Mill recived steam from No. 1 Recovery Boiler and additional requirements were drawn from the Newsmill plant. The addition of the Turbine to generate up to 21,000 KW required an added steam input from the Newsmill plant of some 60,000 pounds per hour. One feature of this system is the use of high pressure heaters to increase feedwater temperatures.

The economic value of a feedwater heater is to add a steam demand into the system which will assist in power generation. The steam flow indicated 19,332 pounds per hour would permit generation of about 725 KW per hour.

Fig. 2 - This represents the summer conditions as they relate to the same steam system. The difference in the steam demand at the turbine inlet is noted to be 416,088 pounds per hour - 350,640 pounds per hour = 65,448 pounds per hour, and the power generation is accordingly reduced to 17,529 KW.



KRAFT MILL- HEAT BALANCE DIAGRAM - BACK PRESSURE UNIT
AVERAGE WINTER CONDITIONS



KRAFT MILL - HEAT BALANCE DIAGRAM - BACK PRESSURE UNIT
AVERAGE SUMMER CONDITIONS

The change in heat demand from winter to summer is severe. Pulp mills, and paper mills too, use huge quantities of water and when this is drawn from the river at 32°F in winter or 80°F in summer the demand for steam changes dramatically.

Winter load condition is influenced by:

1) water temperature
2) raw material temperature (frozen wood chips, etc.)
3) building heating

Turbine Specifications:

The operating conditions were specified as:

Inlet:	Steam Pressure	850 psig
	Steam Temperature	900°F
	Steam Flow	425,000 lbs./hr. (maximum)
Extraction:	Steam Pressure	160 psig
	Steam Temperature	420°F
	Steam Flow	150,000 lbs./hr.
Exhaust:	Steam Pressure	60 psig
	Steam Temperature	350°F
	Steam Flow	250,000 lbs./hr.

The turbine manufacturer's predicted performance curve is shown in Fig. 3. The MEP (most efficient point) was selected to be at 375,000 inlet steam flow, since we felt that the 400,000 flow was very optimistic on a continuous basis.

Fig. 4 - Shows the level of power we expected to be abie to generate, averaging 19.75 MW over the year for a total of 140,837 MWH after allowing idle time and a 90% load factor. Our actual experience was about 16.75 MW and approximately 119,394 MWH over a year.

In explanation of the lower load production we may list the following points which were contributing factors:

1) Steam temperature below design.
2) Turbine oversized.
3) Turbine operating below MEP.
4) Economics of mill operation (i.e. energy conservation).
5) Steam valves leaking on turbine.

It is not possible in the time allotted to discuss in detail the cost impact of the various points mentioned above. The total cost of operation is reviewed later.

Review of Energy Costs

In order to put our costs into the proper perspective we need to develop some comparative figures for consideration.

FIGURE No. 3

Inlet Steam Flow For One 30,000 KVA STAL-LAVAL Extraction Backpressure Turbine Generator

Inlet Steam Pressure	825 p.s.i.g.
Inlet Steam Temperature	900° F
Extraction Pressure	165 p.s.i.g.
Backpressure	60 p.s.i.g.
P. F.	0·80

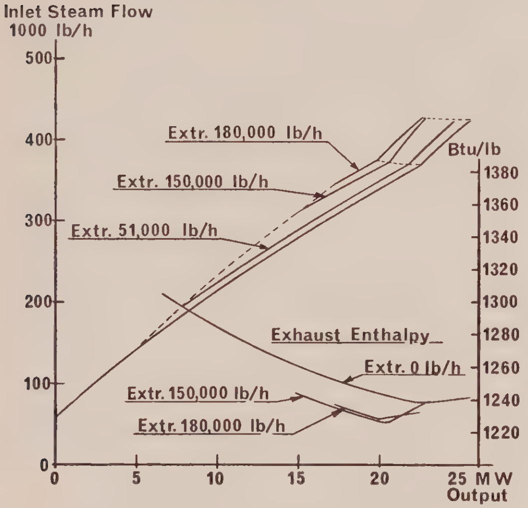
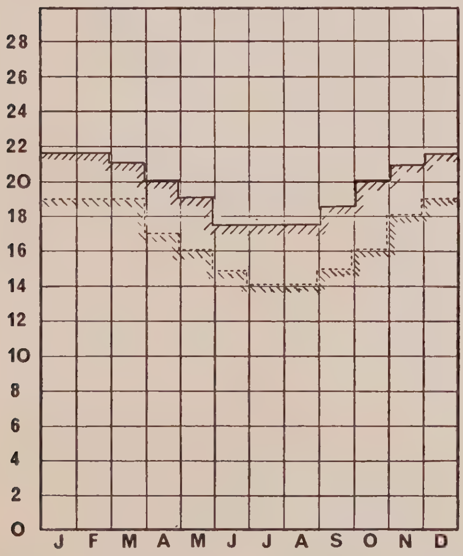


FIGURE No. 4

EXPECTED ANNUAL POWER PRODUCTION No. 4 TURBINE VS. ACTUAL PRODUCTION

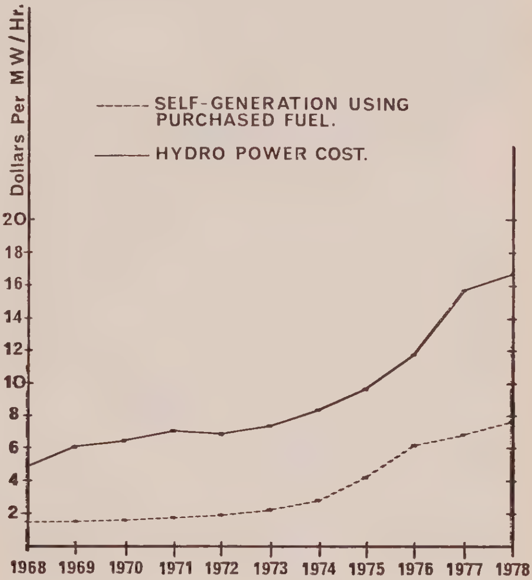


Expected Average 19·75 MW hr.

Actual Average 16·75 MW hr.

Fig. 5 - This curve has been developed to illustrate the historical cost of purchased power versus self-generated power, the basis being our actual Hydro contract costs as compared to our Natural Gas fuel cost. This relationship shows the cost of energy only, and is merely intended to show the share of power cost which may be available to write off capital and operating costs of the venture.

FIGURE No. 5



As a rule of thumb we are trying to keep our self-generated power cost at 50% of purchased power. Fig. 5 shows the relationship as maintained over the past 10 years. The inflationary cost of both Hydro and Natural Gas is evident, and while both costs have risen sharply the difference has widened and shows more potential dollar savings for self-generation.

In 1974 when No. 4 Turbine was installed we could expect a differential of \$5.64 per MWH and in 1978 we expect \$8.75 differetial. To develop the curve for self-generated power costs used in Fig. 5, we have charged 4,300 BTU/KWH fuel valve.[2,3]

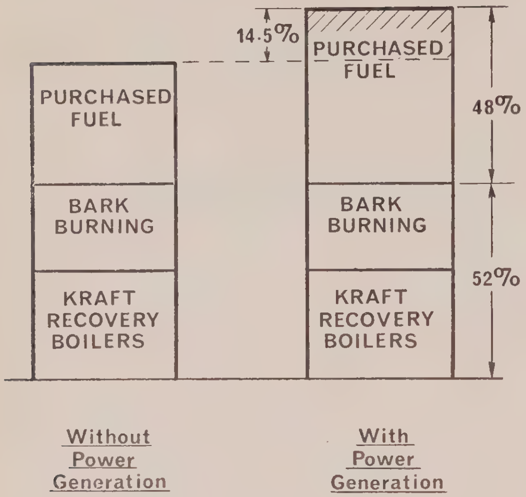
Establishing Cost of System

Any review of steam plant operations will dwell at some length on establishing the cost of steam, which is, of course, reflected in the cost of self-generated power.

In a complex as large as ours it is very difficult to assemble all the costs which are involved in the processing of waste fuel. This year we are looking at statistical data which shows that better than 50% of our heat value comes from waste fuel. This includes black liquor from the Kraft process; bark from

wood handling; sawdust from Stud Mill; bark and sawdust from Waferboard Plant; sludge from effluent system. The value of this waste fuel is in the range of $500-600,000 per month, when compared to purchased fuel of an equivalent heat value.

FIGURE No. 6



FUEL CONSUMPTION

Strenuous efforts have been exerted in the past few years to employ more waste as boiler fuel. The timing of our concern is closely related to the significant increases in the cost of purchased fuel which resulted from action of the OPEC countries. It is not too many years ago that we would not expend much effort to burn bark, rather dispose of it in a dump and purchase fuel for steam generation, simply because these fuels were available at such low cost. This was a common practice at many paper companies.

Because of the difficulty mentioned before of assigning all pertinent costs to our waste fuel programme we found we could not establish a fuel cost on any meaningful basis. Our present approach is to cost steam as if purchased fuel has been burned and credit department producing waste at this fuel value. This results in a higher steam cost than one might normally expect.

I will summarize this discussion by saying that our steam costs could probably be lower and, therefore, our profitability on self-generation of power appear higher if other standards for steam costing were employed. This is largely a choice of internal accounting, which will vary from company to company.

Maintaining Power and Steam Balance

Our heat balance diagram, Fig. 1 and Fig. 2, showed us steam flows indicating "normal" mill operation. Problems arise in power generation when one part of the mill may be upset and usually the first item to be affected is the steam usage. We know our backpressure turbine will produce electric power in proportion to the steam flow to process. When steam usage is altered in one area, power production will be affected. If the mill operation cannot tolerate any power reduction, then it is necessary to resort to some artificial method of maintaining steam demand and power output. This may consist of a dump condenser or a steam-spill system.[4] These systems have been described in detail in other papers, therefore I will restrict myself to comments on our own system.

In our case we selected a steam spill system. This consists of an automatic valve which is actuated by the pressure in the low pressure 60 psi process line. The valve will open on high pressure and spill excess steam to atmosphere.

The No. 4 Turbine is operated on a constant power load control. The load control is set to maintain a predicted KW load, usually as high as possible without opening the spill valve. Upset in the steam system, causing high pressure in the 60 psi line, will cause steam to vent. Fig. 9.

This control has proven to be simple and very effective. However, it is necessary to police this operation closely, since it is very easy to set your power control too high, and thus vent off expensive BTU's. The relationship between spilling steam to generate power or purchasing more power is critical and costly.

Review of Alternative Sources of Power

1. Spilling steam to atmosphere.
   At 400,000 lbs./hr. throttle flow, the turbine will generate 21 MW, or 19,000 lbs./hr. for each MW. Assuming a steam load drop of 19,000 lbs., and venting 19,000 lbs. to maintain 1 MW load, the loss becomes:
   $$\frac{19{,}000 \times 1{,}230 \times 2.11}{10^6} = \$49.30 \text{ per MWH}$$
   This is in addition to the generation cost of $7.56 per MWH.
   TOTAL COST per MWH = $56.86.
2. We have at our disposal a turbine with 3 MW capacity on a straight condensing operation. During extended interruptions in mill operations where steam usage may be interrupted for periods exceeding 12 hours and we are spilling steam continuously, we could use this machine to reduce our losses to atmosphere. This turbine can produce 3.0 Megawatt with a flow of 42,000 lbs. steam per hour or 14,000 per MWH.
   This cost of this operation would be $36.33 per MWH.

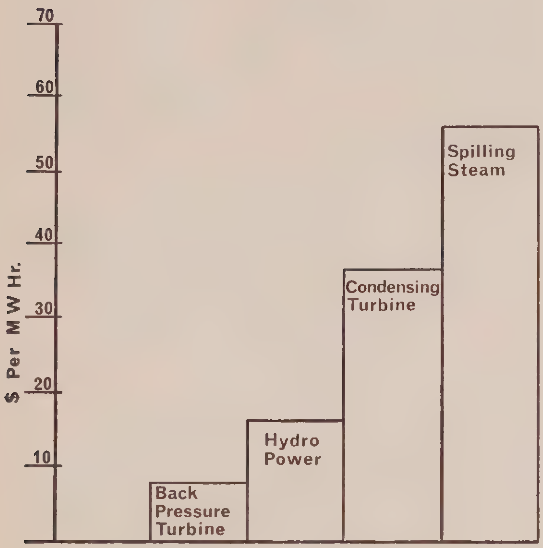
Fig. 7 - This chart emphasizes the difference in cost when using power from various sources. We can spill steam only for short periods, to keep our Hydro take as low as possible.

In the calculation of our generating costs we add the cost of spill steam to the actual steam or heat usage cost for the particular turbine.

In other words our month-end statement would include the following information:

Heat units used per KWH	-	3,800 BTU
Heat in spill steam per KWH	-	500 BTU
TOTAL CHARGE	=	4,300 BTU

FIGURE No. 7



RELATIVE COST OF POWER

Cost of Heat Losses

We are now aware of seriously high power generation costs which can be directly charged to the use of spill steam to generate back pressure power. In Fig. 13 we have identified the costs as they related to our No. 4 Turbine operation. Even with close monitoring of the situation, the loss of heat to the atmosphere in a period of about four years of operation is $369,621. Considering the size of other turbines in operation in our system our losses for the whole plant in four years could possibly exceed $1,000,000.

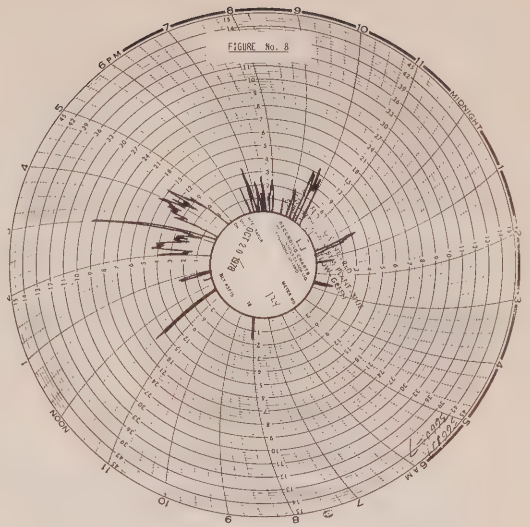
This is a significant energy loss at a time when our country and our company are committed to a policy of energy conservation. We believe joint efforts of our company with Ontario Hydro should be able to reduce these losses significantly. This would certainly make Industrial On-Site Power Generation more attractive to industry, and provide jobs and investment in an area where at present there is a minimum enticement.

Reducing Losses of Spill Steam

Our large modern turbine-generators are all equipped with several control modes of operations.

These are:
1) Speed Control
2) Load (Power) Control
3) Back-Pressure Control

Speed Control is essential on all turbines as a safety device and provides back-up to other control modes. It is the method of control when turbine is operating solo.



Load Controls are used when operating in parallel with Hydro and are applied in several manners. On No. 4 Turbine we have a constant load control which will control the turbine to a pre-set electrical output regardless of steam demand to process. Any excess of steam is spilled to atmosphere. Fig. 9.

In our No. 5 Turbine we employ a "tie-line" control, which modulates the turbine power output to maintain the incoming Hydro tie to some pre-set level. Here again, steam may be passed to atmosphere if power demand is up when process steam is down.

Back-Pressure Control - Operating in this mode, the turbine-generator output is varied in order to meet the demand for steam in the process. That is to say, should some portion of the steam process shutdown, power output is automatically reduced, and there is no spilling of steam. The power demand dropped from the Turbine would have to be picked up on Hydro, and this would form a peak. Fig. 11. Back-pressure control is seldom used because our Hydro contracts use a peak demand method of billing.

Suggested Method of Reducing Spill Steam

Fig. 9 - This is a chart from our spill system which shows the steam loss which occurred on September 5th, when one of our Kraft Mills experienced some mechanical difficulty. The chart is overmarked with concentric circles at increments of 20,000 lbs. steam per hour, which is an approximation of the steam requirement to generate one Megawatt of power. This shows that we were at times generating in excess of 5 Megawatts of power by blowing steam to atmosphere.

It is quite possible that at this time Ontario Hydro may have had power available which could have been used to reduce these losses. In order to do this we could run the turbine with controls in the back-pressure mode. Operating in that manner, the turbine would

drop the electrical load as the steam demand was reduced, saving the steam which would otherwise be blown off.

It is also possible to use back-pressure control at the same time as Load Control on No. 4 Turbine. In such an application, the turbine would generate maximum power when on peak steam demand, and drop power on steam reduction; but it would only drop to the point at which the load control was set. Fig. 12.

At this point you will have realized that we are talking about something different in Hydro contracts than we now have. Something which would allow us to vary our peak without the penalty as it now occurs. In other words, to pay for the power used, but not establish new peak rates.

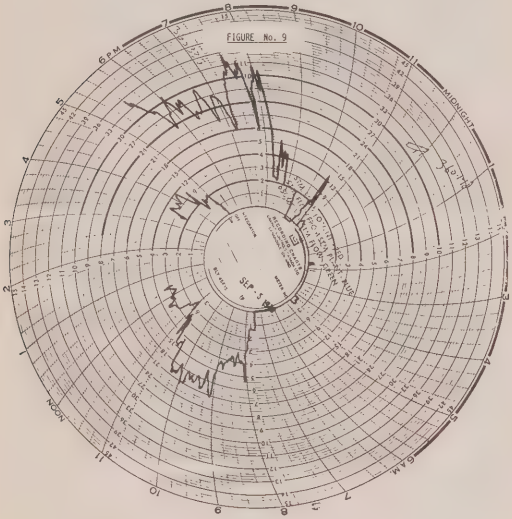
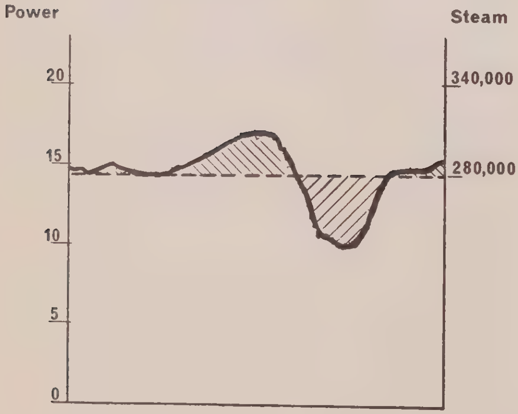
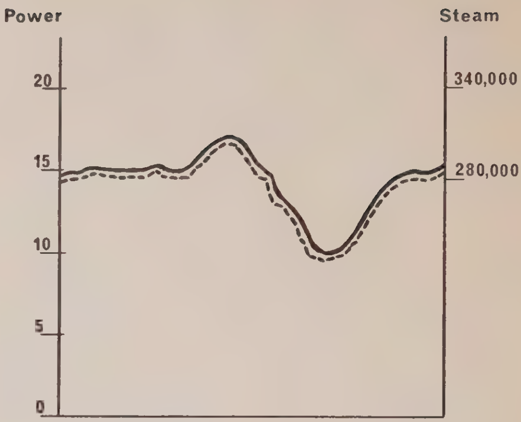


FIGURE No. 10



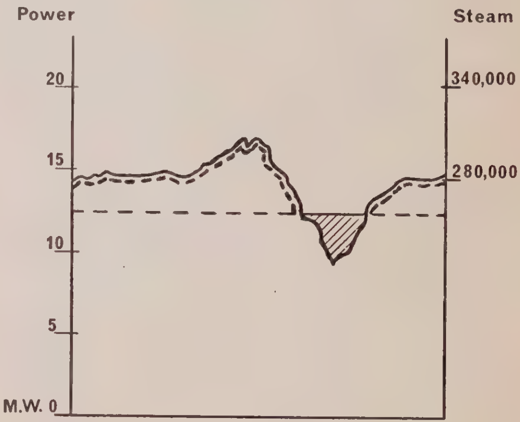
CONSTANT LOAD CONTROL

FIGURE No. 11



BACK PRESSURE CONTROL

FIGURE No. 12



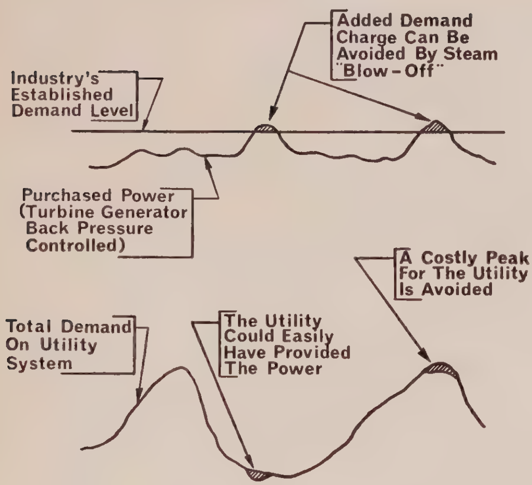
BACK PRESSURE WITH LOAD CONTROL

Cost of Generation - No 4 Turbine

Year	Production MW Hr.	Power Cost	Spill Cost	Equivalent Hydro Cost
1974	57,812	151,467	20,812	477,527
1975	89,100	359,964	74,844	852,687
1976	106,050	638,421	142,107	1,260,935
1977	114,090	770,107	78,772	1,795,776
1978	77,010	582,195	53,136	1,236,964
Total		$2,502,154 $ 369,621	$369,621	$5,623,889
Total Generation Cost:	$2,871,775			$5,623,889

FIGURE No. 14

UTILITY DEMAND



We realize that there may be limitations to the flexibility which can be accepted into the system, since Hydro itself has obligations to meet in its own area of responsibility. But it does appear to us that a system could be arranged which would be of mutual benefit to both parties, and offer encouragement to others to enter the field of cogeneration of electric power.

Summary

In summary, may I conclude as follows:

1) Great Lakes Paper is committed to a policy of industrial power generation.
2) The practice is economically sound and has proven reliable over the years.
3.) Losses which occur during imbalance of the steam system are costly and must be kept under control. This remains our largest single loss of energy.
4) Modified contractural arrangements with Ontario Hydro offer the best answer to improved profitability, as well as improved use of our nation's resources.

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Discussion:

The Importance of Steam Balance for Economic Operations of Industrial Cogeneration

J. R. PARROTT, *Great Lakes Paper Ltd.*

Question: T. Dobie, *Engineering Interface Ltd.*

I was most interested in the problem you have in spill steam. A technique that hasn't been used too much in North America in a situation like that is to use what used to be called the "Marg-Air accumulator" - interposed between the feedwater makeup of your total feed to your deairator. It can be very cost effective, and certainly, in terms of flattening out the energy balance in the plant, very very useful. I suggest that for your investigation.

Question:

I have one question on your graph on the cost of power from Hydro and power from self-generation. You said that the cost differential has increased over the last four or five years between the cost of power from self-generation and from Hydro. Now I also noticed from the graph that between 1973 and 1978, the cost of self-generation has quadrupled from about \$2.00 per magawatt hour to about \$8.00 per megawatt hour, whereas cost from Hydro has just about doubled from about \$8.00 to about \$16.00. If that trend continues, you might just break even after another five years. Would you comment on that?

Answer: Mr. Parrott

This informatio is all taken from our records and, of course the Hydro cost has been going up very substantially. The changes that have happened since we installed the turbine have made us look pretty smart to put the turbine in when we did.

A Typical Industrial Cogeneration Project

A. SCHWARZENBACH,
Brown Boveri (Canada)

The design of a cogeneration project for several chemical plants in the U.S. is presented. To arrive at an economic solution, various extraction turbines were studied. This project, with its economic evaluation, was carried out by a consultant. The evaluation of the number of boilers, of the live steam conditions, and of the number of turbines is shown. The final solution with three boilers and a single double-extraction turbine is presented.

Introduction

The gradual depletion of primary energy sources in the United States of America is well known. This country has, for several decades, obtained oil and natural gas in abundance from its own ground. However, this period is over. The additionally needed oil is now imported at much higher prices and taxes the balance of payment heavily. The policy of the government therefore is to restrict the use of natural gas boilers for industry and utilities. Every extension of industrial plants should use the "new" national fuel, coal. Natural gas is often used for industrial processes. The chemical industries are therefore replacing the natural gas used for the existing boilers by coal, thus saving the natural gas for processes in the new plant extensions.

This fuel change-over, the rapidly growing cost of electricity plus the cogeneration energy bill passed by the House of Representatives are the reasons for the following cogeneration project for chemical plants in Geismar, Luisiana. The five chemical firms Borden, Uniroyal, BASF, Shell and Vulcan commissioned the consultant firm Burns and Roe in Oradell N.J. with the development of a common cogeneration plant burning coal. These companies required three different pressure levels of process steam. The consultant established the optimum project using several tenders from Brown Boveri for double extraction-condensing and double extraction-backpressure steam turbine. I should like to thank Burns and Roe for their permission to present in brief the cogeneration plant layout and the economic evaluation.

Project Location

Fig. 1 shows the geographical location of the five chemical plants near the Mississippi river at Geismar. The power station is to be erected near the BASF works. The coal arrives by barge and is stocked between the unloading facilities and the power station. The waste disposal area is situated on the northern boundary. The project left enough space for the future extensions of all five plants.

Economic Data and Planning Criteria

The following data and assumptions apply:

- interest rate	10%/a
- plant life for depreciation	20 a
- taxes and insurance costs on capital investment	2.7%/a
- payback period for investments	5 a
- interest during construction (S-curve investment schedule)	10%/a
- escalation for equipment and capital costs	8%/a
- electric utility rate forecast by Gulf State Utilities increased by 10%	doubling by 1982 triplication by 1987
- utility stand by demand charge in 1977	2.30 ($/kW)/mon = 27.6 ($/kW)/a
- wages in 1977 operators and maintenance	11 $/h

- supervision 12.65 $/h
- wages escalation 10%/a
- working capital two initial months of operating expenses

The five chemical plants run every day of the year in three shift operation. The need for process steam is a steady baseload. No part loads or peaking considerations are necessary.

Optimization

The electrical power used by the five plants today is about 400 MW, so the cogeneration should produce a considerable part of it. Condensing turbines were considered. The first BBC turbine tender showed the price of a 60 MW double extraction condensing turbine to be about 150% of the price of a 35 MW extraction-backpressure set. For the condensing turbine, the larger boiler, the condensor and the cooling water circuit entail additional cost. It was therefore obvious that the condensing type could not be entertained. In the next step, BBC supplied 6 tenders for different double extraction-backpressure turbines. There were three 100% and six 50% units for different live steam conditions. These pressures and temperatures are:

p 16.65 MPa (2400 psig)
t 538 °C (1000 °F)
p 12.5 MPa (1800 psig)
t 538 °C (1000 °F)
p 10.4 MPa (1500 psig)
t 482 °C (900 °F)

The live and process steam flows are:

live steam	189 kg/s (1.5 Mlb/h)
hp extraction at p = 7.9 MPa (1131 psig)	44.1 kg/s (0.35 Mlb/h)
lp extraction at p = 4.84 MPa (688 psig)	63 kg/s (0.5 Mlb/h)
backpressure at p = 1.66 MPa (227psig)	81.9 kg/s (0.65 Mlb/h)

The cost comparison was made taking the lowest conditions as a basis. The differences in capital costs were 2.86 and 8 Mill $ for the higher steam conditions. See Fig. 2. The mean gain in the annual operation costs during the first 5 years is: 1.99 and 2.56 Mill $/a. The payout time for the medium conditions compared to the basic conditions is therefore only 1.4 years, but for the highest steam conditions it is 8.8 years. According to the planning criteria the medium steam conditions were chosen.

Another investigation concerned the choice of the boiler size, e.g. the use of several boilers. The following alternatives were checked:
2 x 57% / 3 x 33% / 3 x 50% / 2 x 67% / 4 x 40%. The consortium finally decided on three 40% boilers. This solution meets the incremental growth of the cogeneration facility and provides enough capacity to make up for the loss of one boiler.

A solution with a single 100% steam turbine was compared with 2 x 50% steam turbines. The investigation showed for the two turbines solution too small a gain in operating costs compared with the increased capital costs. The single turbine was retained.

The Project 1977

The 1977 project, according to Fig. 3, comprises 3 boilers, a double extraction-backpressure turbine and a feedheating system for the condensate and the make up water. It is estimated that 1/3 condensate will be returned and 2/3 will be provided by make up. The elec-

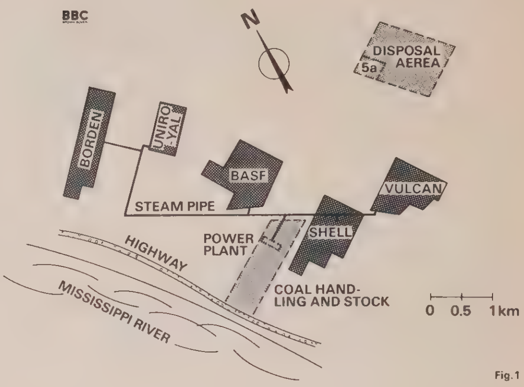


Fig. 1

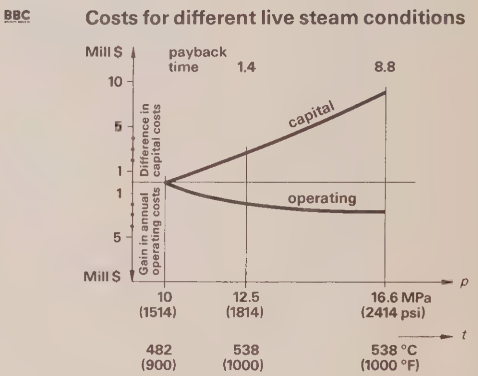


Fig. 2

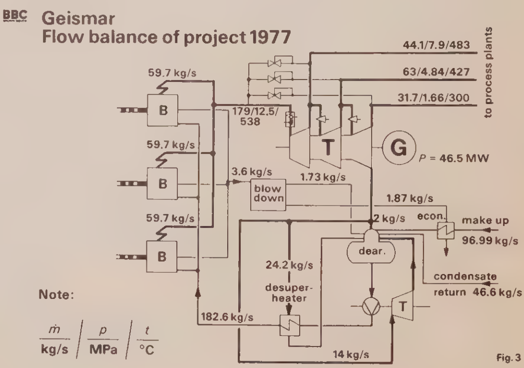


Fig. 3

tricity is supplied to the adjacent BASF plant and credited to the other partners. The total plant costs are estimated at 126 Mill. \$. The cost of steam in 1982 is estimated to be:

Process steam without credit for electricity	$14.2\ \$/t = \frac{6.5}{1000}\ \$/lb$
Process steam with electricity credit	$11.4\ \$/t = \frac{5.2}{1000}\ \$/lb$

Only 4.6% of the final steam costs are caused by the investment of the turbine generator and the electricity distribution. However, the credit for the electricity is 25% of the resultant steam costs.

The Design of the Turbine Generator

The final project is the result of the described investigations for economic solutions with several types of turbines. The architect engineer received turbine tenders from Brown Boveri and other manufacturers. Quick tender submission was possible due to a special design system for industrial steam turbines developed by BBC. The modular design system shown in Fig. 4

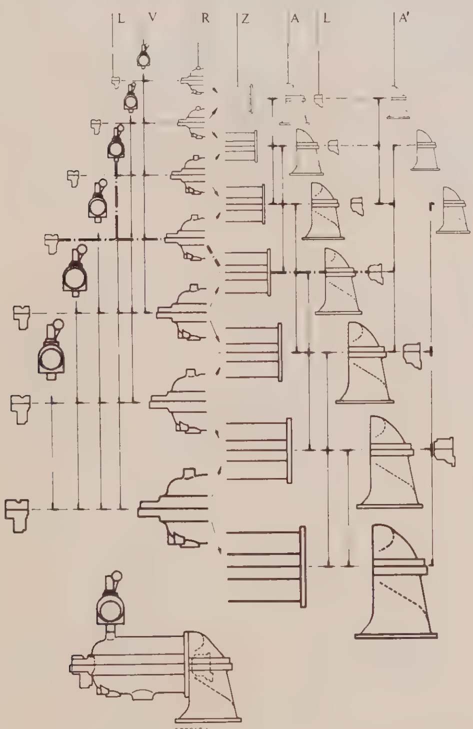


Figure 4
Modular system for BBC industrial turbines
L Bearing pedestals
V Valve casing
R Inlet section
Z Intermediate section
A Exhaust section
A' Exhaust section for higher back pressures

was introduced some years ago. In the modular system, the turbine is split into 5 main parts, namely
- bearing pedestals at both ends
- admission part or valve casing
- inlet section
- intermediate section
- exhaust section

Each of these parts consists of predesigned geometically graded sizes which can be combined in various ways. The main advantages are:
- quick submission of turbine tenders
- optimum adaption to customer needs
- short delivery times
- repeated use of proven elements.

This design offers the advantages of tailor-made components without the disadvantages of earlier designs. Streamlined working methods, component organisation and sophisticated computer programs are employed in design and manufacture. The repeated use of standard elements is very important for the reliability of a turbine.

Fig 5 shows a cross section of a single automatic extraction condensing turbine. On the left on top of the turbine the steam is admissed through the stop valve and the 3 control valves. On the left of the main casing is the inlet section, together with the intermediate section and on the right is the exhaust section. In the middle of the turbine is the extraction section consisting of extraction control valves, low pressure nozzle casing and the extraction nozzles. These valves control the extraction pressure automatically at the preset value over the whole output range. In double extraction turbines two of the extraction sections are used.

Fig. 6 shows a double automatic extraction condensing turbine during erection. The steam inlet is on top on the right and the exhaust is in the foreground in the photograph. The shaft has three control wheels and a reaction part after the first and the third. A nozzle box is provided for the live steam inlet section, two blade carriers for the reaction stator blades and two low pressure nozzle casings. The bearing pedestals are fixed on the main casing, which is supported on the foundation. The shaft, therefore, follows the movements of the casing. The rotor is made from a high quality single piece forging and its bearing and coupling sections are standardized. Fig. 7 shows a rotor of this type for a 48 MW extraction backpressure turbine. This machine is now ready for operation in Claiborne, Alabama. The turbine was pre-assembled in the workshops and shipped as a package to the site. This method reduces transportation problems and accelerates erection on site.

The Air-Cooled Turbo-Generator, Serie WX

The Brown Boveri industrial turbines are supplied with air-cooled generators, of the well known two-pole turbo-type with cylindrical rotor and self-ventilation as shown on Fig. 8. Two axial fans, fixed on the shaft extensions at each end, supply cooling air at the necessary rate to cool all generator parts adequately. Usually, a closed circuit air cooling system is applied to

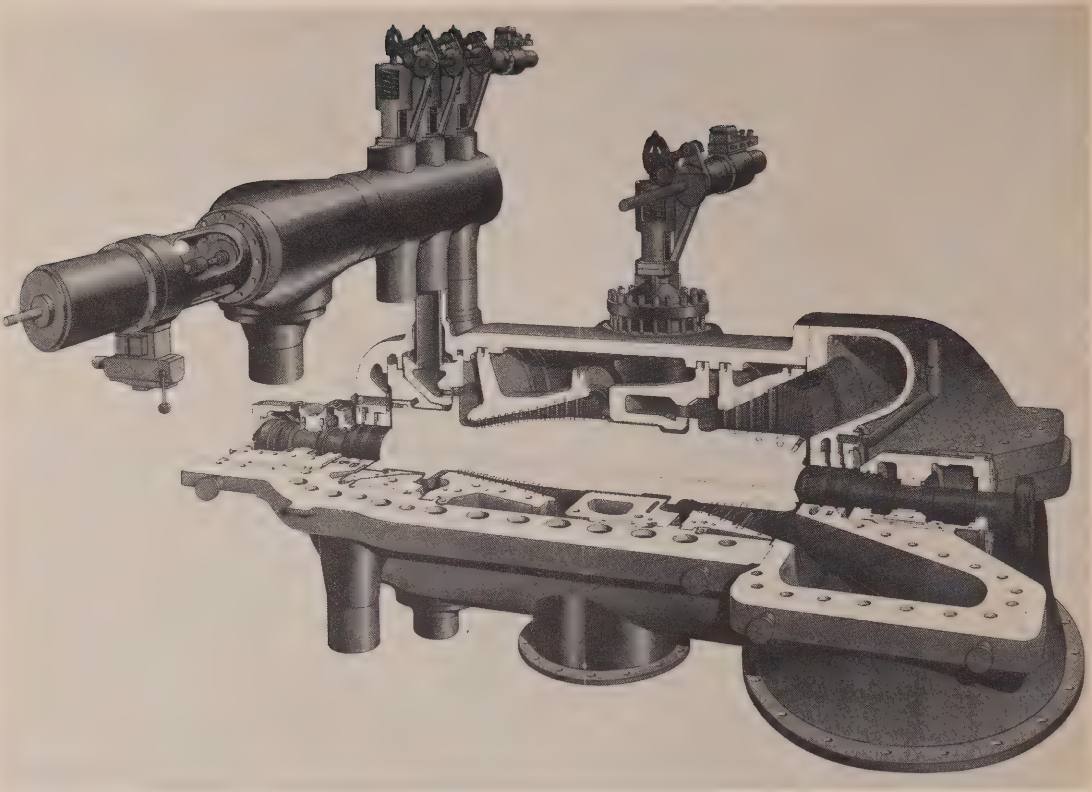


Figure 5
Single automatic extraction condensing turbine.

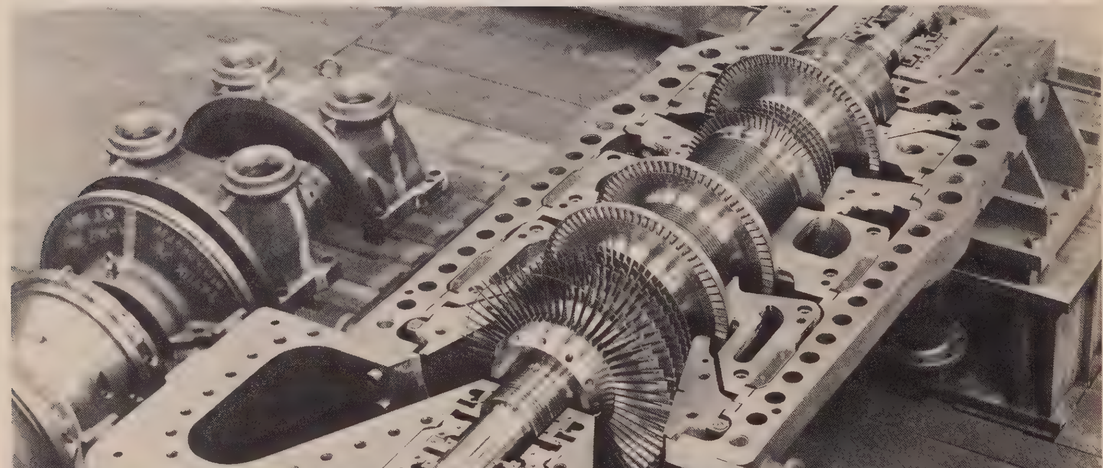
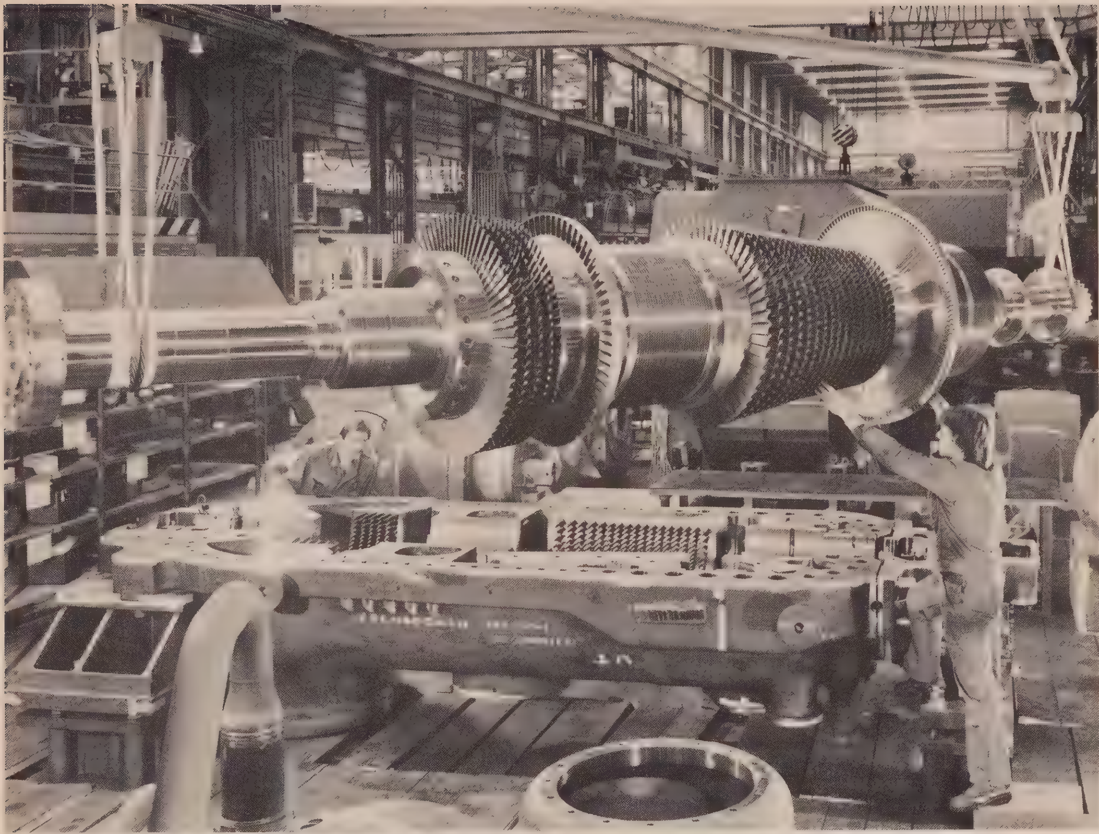


Figure 6
Double automatic extraction condensing turbine.



0**Figure 7**
Single extraction condensing turbine during shop erection.

BBC

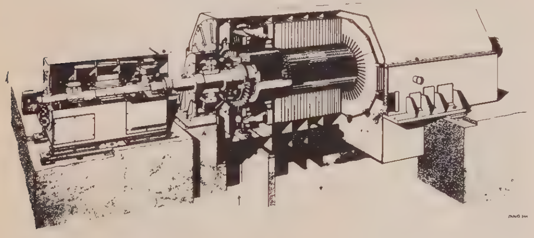


Fig. 8
Air-cooled turbo-alternators type WX

prevent internal contamination of the generator, which is often met with in open-air circuit air cooling.

As regards cleanliness and reliability, the air-cooled turbo-generator with closed circuit air cooling is in no way inferior to the hydrogen-cooled generator.

The stator winding is indirectly cooled, the heat being dissipated through the insulation and through the stator iron in the vicinity of the slots. The rotor winding is made of hollow conductors which are in direct contact with the cooling air.

The direct cooling of the rotor windings offers excellent utilization of material and as a result smaller overall dimensions and weights, when comparing it with the indirect cooling mode.

The heated air is cooled by air-to-water heat exchangers, which, in case of steam turbine driven generators, are normally located in the basement (see Fig. 9).

The flow and distribution of cooling air inside the generator are conducted in such a manner, that uniform temperature distribution is achieved throughout the machine. This is ensured, among other things, by radial ventilation ducts in the stator core, evenly distributed in axial direction.

The stator winding is subjected to vacuum pressure-impregnation (VPI), whereas for all generators described herein the Brown Boveri systems Micadur or Micadur-Compact (trademarks) are supplied. With the Micadur system the stator bars are impregnated one by one, with the Micadur-Compact system all the stator bars are impregnated together with the core. Both systems offer excellent qualities regarding dielectric and mechanical strength, and the windings im-

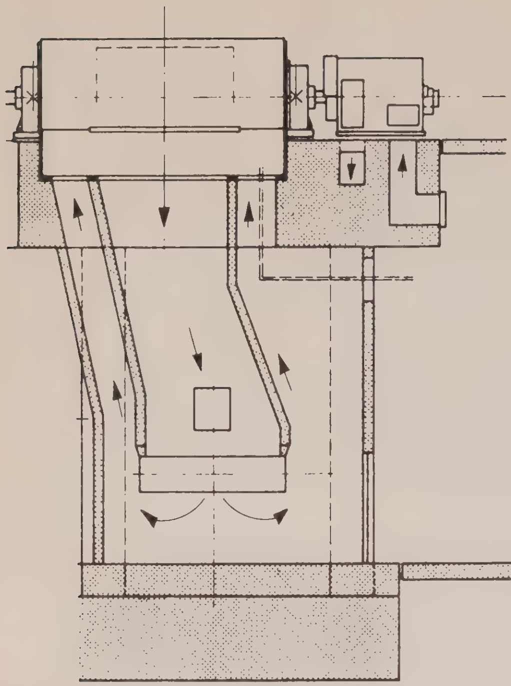


Fig. 9
Closed circuit air cooling system with heat exhangers in basement

pregnated in this manner are oil-, dirt- and water-resistant, flame proof and self-extinguishing.

Both stator and rotor windings are insulated with class F material. As each generator, however, is utilized to the limits of class B only, a practically unlimited service life can be expected.

Particular attention is paid to the arrangement of the rotor winding and the rotor end-bells. The end-bells are overhung on the rotor end region. This means that any forces arising from winding heat dilation, cannot be transmitted to the shaft ends and hence the vibrational behaviour is not affected.

At each end, the rotor is supported by a pedestal bearing.

The generators described herein cover an output range of 20 130 MVA approx. with three frame sizes:

WX 14 L : 20 - 40 MVA
WX 16 L : 40 - 70 MVA
WX 18 L : 70 - 120 MVA

The generators are available with voltages ranging from 5 - 15 kV, depending on rating and frequency. The standard voltage for 60 Hz operation is 13.8kV.

Brushless Excitation

High utilization factors, low short-circuit ratios of 0.4 to 0.6 and insistence on dependable, low-maintenance generators led to the brushless excitation system. For generators having ratings above 20 MVA, Brown Boveri employ an excitation system with power obtained from a pilot exciter with permanent magnet poles. Further, this exciter is fitted with diode fuses, a diode monitoring device, and a supporting bearing.

In this configuration, shown in Fig. 10/11, the type WBT brushless exciter is used together with the integrated permanent-pole generator m3 as the auxiliary exciter. This feeds the field winding of the main exciter m2 via the final control element of the voltage regulator. In this way, the excitation system can be made completely independent of the distribution network.

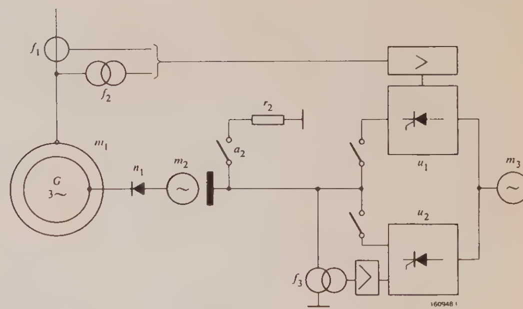


Figure 10
Excitation circuit of a brushless exciter system with power supply from a permanent-magnet generator

a_2 = De-excitation switch
$f_1 f_2$ = Instrument transformers
f_3 = Current transformer
m_1 = Generator
m_2 = A.C. exciter
m_3 = Permanent-magnet generator
n_1 = Rotating rectifier
r_2 = De-excitation resistor
u_1 = Voltage regulator, auto
u_2 = Voltage regulator, manual

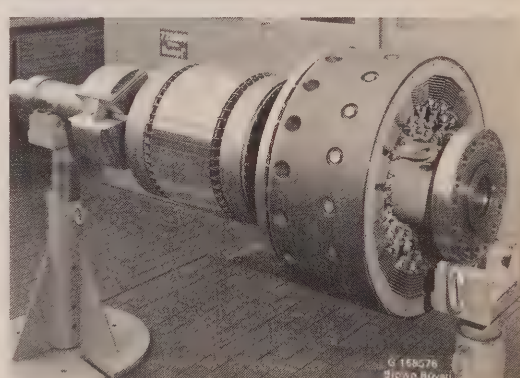


Figure 11
Rotor of a brushless exciter type WBT mounted on the shaft; from left to right are the permanent-magnet poles, the rotor of the a.c. exciter and the diode carrier ring.

Exciters in a more simple version, series WBF, without permanent pole generator and fuses are available too. They are overhung on the generator shaft end.

Electronic-Hydraulic Control

The electronic control system "Turboturn 4" is used. This is a modular system, which can be easily adapted to the particular requirements of all types of turbines. The pressures are transformed into voltage signals proportional to the pressure value. See Fig. 12. The speed is measured by a counter on the turbine shaft. With this information the "Turboturn 4" sets the control valves by means of the electro-hydraulic transducers. This system was described in detail in Brown Boveri Review 1976, No. 6, by K. Wirz. 14 turbines are already operating with this modern control system.

Final Remark

This paper shows that, despite heavy capital costs, resulting from coal fuel, industrial cogeneration with modern plant layout and modern steam turbine design is an economic solution.

BBC

Electronic control for industrial steam turbines

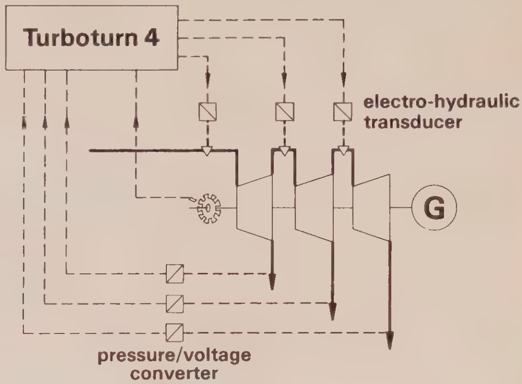


Figure 12
Electronic control

Discussion:

New Approaches in Industrial Cogeneration

MR. SCHWARZENBACH *Brown Boveri (Canada) Ltd.*

Question: John McGeachy, *Queen's University*

I was very interested in your picture of a rotor there; it looked like one of Brown Boveri's fabricated rotors, one of them that was hoisted up ready to go in a lower half cylinder. My question: have you done much research into the application of other fluids in power recovery from lower temperature heat sources with turbo machinery?

Answer: Mr. Schwarzenbach

No. Not up to now.

Concluding Remarks

D. J. GORDON
President, Ontario Hydro

Well, I suspect that after two solid days of speeches and papers you are wondering when that "Third Day" of Mr. Auld's will arrive so that you can have a break. Or perhaps you feel a little like the chap who was telling a colleague about a very learned and technical 500-page volume he'd just finished on the Sex Life of the Penquin. "I've learned a lot more about penguins," he sighed, "than I really wanted to know."

I'm sure in the past two days you've heard more than you really wanted to know about the economics of cogeneration. And it's my (not very enviable) task to try to summarize for you just what you have heard. Bearing in mind the penguins, I'll try to keep it as short, and therefore, sweet, as I can.

The primary objective of the seminar was to put cogeneration in focus for all of us — government, the utility, industry, the consultant and the manufacturer — so that we would have a better understanding of the what, where, when and how of its potential contribution to the solution of the energy supply and energy cost problems facing Ontario industry.

By your attendance, interest and contributions to the discussion, you have brought cogeneration into much better focus. I hope you will agree that jointly we have sorted out some of those paradoxes to which the minister referred at the outset. And I particularly wish to thank the session chairmen and the speakers for their contribution in making this conference a success.

Mr. Auld clearly stated his Ministry's interest in and commitment to the advancement of cogeneration as a way of improving the efficiency of energy use and of achieving the long-term goal of energy conservation.

Other speakers over the past two days have agreed that by-product, or cogeneration, power has a great deal to offer industry in the form of:

*First - established technology
Industry in Ontario can utilize various types of cogeneration systems.

*Second - relatively low capital investment
Several speakers (Messrs. Newby, Lindvall, McCullum and others) have indicated that capital costs are low for base load generation, certainly lower than Ontario Hydro costs.

*Third - lower energy costs. Mr. Parratt and Donald Dick have shown that cogeneration systems must be operated at high load factor to achieve lower costs, just as Ontario Hydro attempts to maintain as high a load factor as possible on all operating generating units. There is another similarity. With its present high reserve, Ontario Hydro is attempting to market this excess capacity to our neighbours in the U.S., in much the same way as Ontario industries wish to market their surplus capacity to us. We understand the problem.
As Mr. Parratt noted, the balance between steam requirements and electrical usage is important for economic operation — and economic operation depends on a number of different factors such as — good design; high load factor operations; a system in good operating order which means that maintenance is performed quickly; availability of inexpensive fuel
(Again there are parallels with the Hydro operation).

*Fourth - use of by-product fuel
The economic significance of using readily available by-product fuels, such as wood by-product, was noted by several speakers.

*Fifth - envrionmental benefits
There are environmental benefits to be gained from the burning of by-products as fuel in boilers for cogeneration, as the Hearst Study has shown.

*Sixth - more efficient steam operating and lower cost for steam.
Cogeneration systems can impove operation of boilers and reduce the cost of process steam by about 10 per cent. (Mr. Schwarzenbach's paper.)

It's obvious that there are a number of questions to be answered from industry's (or the customer's) point of view:

*how can a high rate of return on investment in cogeneration be achieved?

*what specific approach to cogeneration best suits a company's needs for steam and electricity within the constraints of its present process or processes?

*what are the long-term prospects for energy supply — gas, oil and coal?

*how can the industry best use its waste by-products as fuel?

*what are the prospects for obtaining more favorable arrangements from Ontario Hydro for standby power, purchase of surplus energy and long-term contracts for purchase of firm electricity supply from industry?

*what is the reliability of electricity supply from Ontario Hydro?

Consulting firms also have an important role to play (and can reap some benefits). They can provide leadership through their expertise in industrial steam supply and cogeneration, placing them in the forefront of industry's efforts toward energy conservation. Additional Canadian experience would strengthen their ability to compete in the rapidly growing and large market for cogeneration south of the border and in the developing countries.

Manufacturers too, can make a contribution, which again will bring a return:

*they can assist consulting firms in providing leadership toward wider application of industrial cogeneration. This growth in industrial cogeneration will enlarge the market for smaller turbines and generators and assist in making their manufacturers more competitive in international markets;

*they can assist industry in developing a capability to maintain the cogeneration units.

Ontario Hydro participants in the seminar have filled you in on another side of the story. Their words have, I feel, been very encouraging. We at Hydro believe:

*that there is significant potential for cogeneration in Ontario in the next decade;

*that the cost of paralleling industrial cogeneration with the Ontario Hydro system would be quite small, and that in this area Hydro's expertise could be made available to industry;

*that there are currently in place rates which could be used to meet requirements for standby power and agreements which could provide the basis for purchases of energy from cogenerators. (Representative figures have been provided indicating the value to Ontario Hydro of cogeneration capacity committed for various periods of time, and further indications have been given of the direction in which we are heading with respect to rates used in conjunction with cogeneration;

*we have also noted that experience in the U.S. suggests consideration should be given to a joint venture between industries with cogeneration and a private "utility" responsible for the overall design, construction, operation and maintenance of the installations.

All in all, while a great many questions have been asked, more than a few answers have been provided (or at least begun) as well. The question of Hydro's current surplus capacity — perhaps the key paradox mentioned by the Energy Minister — is a case in point.

Hydro is prepared to offset any short-term disadvantages against the longer-term gains of efficient utilization and energy conservation. In our view, it is unlikely that there will be large amounts of cogeneration on the system for, say, 10 years, by which time Hydro's surplus capacity will be disappearing. The point is, that advance planning for and commitment to cogeneration must be made very soon if Hydro is to make allowance in its system planning for loads that it will not be supplying and power that it might be purchasing.

And as the Minister phrased it — what about Day Three? There is obviously a great deal to be done, but I do believe we have gained a much clearer understanding of what is to be done, where, when, how, and by whom —

*Industry must reassess its energy needs and identify opportunities for reducing its energy costs through cogeneration; take a closer look at the joint venture approach, and sit down with some of us at Hydro to discuss how we might assist in realizing these opportunities.

*Government must assist with demonstrations of new approaches to cogeneration, such as wood waste utilization and gas turbines for small industries, and continue discussions with all interested parties. They must keep the pot boiling and new ideas and initiatives percolating.

*Hydro, I note, has an even longer list of responsibilities such as:

disseminate information from this seminar;
provide findings from our most recent study on cogeneration costs, together with the results of our cost benefits analysis;

assess new directions for rates that will encourage cogeneration;

present new policy initiatives on industrial cogeneration for consideration by the Ontario Hydro Board;

work actively with industry to encourage cogeneration. (This would bring long-term benefits to Ontario Hydro and could take the form of seminars for operating and maintenance personnel in industry.)

In conclusion, I would like to suggest that "Day Three" starts right now. There are at least two programs that could be initiated immediately as a result of this seminar:

*The Ministry of Energy can set to work with industry and Ontario Hydro to identify potential cogeneration demonstrations, and can assess potential incentives that would encourage cogeneration.

*Ontario Hydro meanwhile can undertake to visit all potential users of industrial cogeneration to discuss in depth the issues raised over the last two days and to assess what assistance we might provide in specific cases.

*And, industry, consultants and manufacturers can give serious consideration to the formation of a joint venture development for cogeneration in Ontario.